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**STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD**

IN THE MATTER OF PROPOSED NEW REGULATION,
20.2.50 NMAC – Oil and Gas Sector – Ozone Precursor Pollutants

No. EIB 21-27 (R)

DIRECT TESTIMONY OF ELIZABETH BISBEY-KUEHN AND BRIAN PALMER

Elizabeth Bisbey Kuehn

My name is Elizabeth Bisbey-Kuehn. I am the Bureau Chief of the Air Quality Bureau (“Bureau”) of the New Mexico Environment Department (“NMED” or “Department”). I am presenting this written testimony on behalf of the Department in this proceeding before the Environmental Improvement Board (“Board”) on the Department’s proposed new air quality regulation at 20.2.50 NMAC (“Part 50”). This part of my direct testimony will address the following topics:

- Facility and equipment data compiled for this rulemaking from the Bureau’s TEMPO database (Part II. of this testimony);
- Key exhibits referred to throughout my and Mr. Palmer’s testimony on the proposed rule requirements (Part III of this testimony);
- The proposed provisions in Sections 20.2.50.1 through 20.2.50.112, and 20.2.50.127 of Part 50; and
- The proposed provisions in Sections 20.2.50.113 through 20.2.50.124 of Part 50 with respect to applicability, description of equipment or process, control options, and proposed rule requirements. Mr. Palmer’s testimony will cover Sections 20.2.50.113 through 20.2.50.124 with respect to the basis for the proposed requirements, estimated reductions, and estimated costs.

1 I will also be presenting direct testimony on other topics in this rulemaking in separate pieces of
2 pre-filed testimony.

3 **Brian Palmer**

4 My name is Brian Palmer and I am a Senior Environmental Scientist with Eastern Research
5 Group, Inc. (“ERG”). I have been asked to provide testimony on behalf of NMED in this
6 proceeding regarding Part 50. I am part of a team from ERG that was contracted to assist the
7 Department in developing the requirements in Part 50 and to provide testimony before the Board
8 at the hearing on the proposed rule. My testimony covers Sections 20.2.50.113 through
9 20.2.50.124 with respect to the basis for the proposed requirements in those Sections, the estimated
10 emissions reductions from compliance with those requirements, and estimated costs of
11 compliance.

12 **I. QUALIFICATIONS**

13 **A. Elizabeth Bisbey-Kuehn**

14 A summary of my background and qualifications is provided in my other pre-filed
15 testimony at NMED Exhibit 5. My full background and qualifications are set forth in my resume,
16 which is marked as NMED Exhibit 6.

17 **B. Brian Palmer**

18 I have been a Senior Environmental Scientist with ERG since 1996. Prior to that, I was an
19 Environmental Scientist with Radian International LLC for five years. My experience at ERG has
20 included development of proposed amendments to EPA’s regulations at 40 CFR Part 98, Subpart
21 W – Mandatory Greenhouse Gas Reporting for Petroleum and Natural Gas systems; leading
22 regulatory development projects for fifteen source categories, including baseline emission

1 inventories and estimating emission reductions; and supporting numerous projects related to the
2 mandatory greenhouse gas reporting regulations at 48 CFR Part 98.

3 My full background and qualifications are set forth in my resume, which is marked as
4 NMED Exhibit 33.

5 **II. FACILITY AND EQUIPMENT DATA FOR PROPOSED PART 50**

6 The Bureau utilizes a database called "TEMPO" to record, monitor, and track information
7 about equipment and facilities regulated by the Department under the New Mexico Air Quality
8 Control Act ("AQCA") and the Board's air quality regulations at Title 20, Chapter 2 of the New
9 Mexico Administrative Code ("NMAC"). This information is collected from different types of
10 submittals, including notice of intent registrations, air quality permit applications, compliance
11 reports, report submittals required by state and federal air quality regulations, settlement
12 requirements, and emissions inventories.

13 In TEMPO, a facility-level entry is referred to as the "Agency Interest" or the acronym
14 "AI." Each facility entered in TEMPO includes: the company that owns, operates, and is the billing
15 party for the facility; the person designated as the main contact or consultant for air permitting
16 submittals; the estimated, potential, and actual quantities of facility-wide emissions; location
17 information; applicable air quality regulations; the reported NAICS and SIC codes; and general
18 information related to the facility. The general information includes identifying numbers assigned
19 by the Bureau, the general category of industry type (such as compressor station, tank battery, or
20 refinery), and the source classification status for facilities with air quality permits or registrations.

21 Additionally, TEMPO maintains information about individual equipment, which is
22 referred to as the "Subject Item" or the acronym "SI." The information maintained for individual
23 equipment will depend on the particular state and federal regulations that apply. Facilities with an

1 issued air quality permit have extensive information about emitting equipment entered in TEMPO.
2 At the equipment-level, at a minimum, TEMPO captures the following: equipment stack
3 parameters (including diameter, height, velocity, flow rate, and temperature); operating hours;
4 permitted hourly and annual air emission limits for all regulated air contaminants; air increment
5 consumption; control device if used and control efficiency; fuel type, heating value, and fuel use
6 rates; general information such as serial numbers, manufacturer and construction dates, operating
7 or capacity rates; applicable federal regulations and subparts; and source classification codes
8 (“SCCs”).

9 The Bureau maintains the SI level of information for equipment at facilities with air quality
10 permits but does not enter the SI level of information for facilities operating with a notice of intent,
11 which is not an air quality permit.

12 The Bureau uses TEMPO and the equipment and emissions data in the database in multiple
13 ways. Electronic copies of public records and documents related to permit applications,
14 compliance reports, emissions inventory, and a variety of submittal requirements are maintained
15 in TEMPO. The emissions data in TEMPO is used to assess annual emission fees and annual
16 permitting fees. The Bureau reports federally mandated regulatory information to EPA via
17 TEMPO. Companies, regulated facilities, consultants, and the Bureau use the information in
18 TEMPO to determine surrounding sources for air dispersion modeling analyses required for air
19 permit applications. AQB uses TEMPO data to track prevention of significant deterioration
20 increment consumption and/or expansion. TEMPO is also used as a project management tool to
21 track action dates and deadlines for multiple sections within the Bureau.

22 Since TEMPO is a database, the Bureau has many options for compiling information
23 according to business need. The data extracted from TEMPO is normally returned as spreadsheets.

1 The Bureau commonly uses reports to analyze emission trends, analyze application submittal
2 trends, respond to Inspection of Public Records Act requests, generate lists of historical permit
3 actions, generate lists of active or closed facilities, and track open actions. The Bureau can create
4 custom reports based on any information in TEMPO.

5 To provide underlying data and information for this rulemaking on proposed Part 50, the
6 Department downloaded the following information from TEMPO and provided it to ERG: owner,
7 facility name, AI ID, source type, county, latitude, longitude, source classification, equipment
8 type, category, designation, description, manufacturer, model number, serial number,
9 manufactured date, construction date, operating rating capacity, maximum rating capacity, type of
10 pollutant, quantity of hourly emissions, quantity of annual emissions, primary and secondary
11 control devices, type of fuel, hours of operation, applicable federal air quality regulations, and
12 SCC information. ERG used this data to develop the equipment spreadsheets used to evaluate the
13 emissions reductions and costs of Part 50. The NMED data pulled from TEMPO and provided to
14 ERG is included in a tab in each equipment spreadsheet, and is referred to throughout this
15 testimony as the “NMED Equipment Data.” The ERG spreadsheets generated from the TEMPO
16 data are provided as exhibits in electronic format as Microsoft Xcel files.

17 **III. KEY EXHIBITS**

18 The Department and its consultants at ERG developed and/or relied upon a number of key
19 documents in developing the proposed rule and the supporting technical information, and these
20 documents are referred to throughout this testimony. The following list contains the exhibit
21 number, name as referred to in the testimony, and description or citation information for each key
22 document:

- 1 • **NMED Exhibit 34 – “EPA CTG”**: EPA Office of Air and Radiation, *Control Techniques*
2 *Guidelines for the Oil and Natural Gas Industry*, EPA-453/B-16-001 (October 2016)
- 3 • **NMED Exhibit 35 – “NSPS Subpart OOOO”**: EPA New Source Performance Standards
4 at 40 C.F.R. Part 60, Subpart OOOO - Standards of Performance for Crude Oil and Natural
5 Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After
6 August 23, 2011 and on or before September 18, 2015.
- 7 • **NMED Exhibit 36 – “NSPS Subpart OOOOa”**: EPA New Source Performance
8 Standards at 40 C.F.R. Part 60, Subpart OOOOa - Standards of Performance for Crude Oil
9 and Natural Gas Facilities for which Construction, Modification or Reconstruction
10 Commenced After September 18, 2015.
- 11 • **NMED Exhibit 37 – “Pennsylvania GP-5”**: Pennsylvania GP-5, GENERAL PLAN
12 APPROVAL AND/OR GENERAL OPERATING PERMIT BAQ-GPA/GP-5 for Natural
13 Gas Compression Stations, Processing Plants, and Transmission Stations.
- 14 • **NMED Exhibit 38 – “Pennsylvania GP-5A”**: Pennsylvania GP-5A, GENERAL PLAN
15 APPROVAL AND/OR GENERAL OPERATING PERMIT BAQ-GPA/GP-5A for
16 Unconventional Natural Gas Well Site Operations and Remote Pigging Stations.
- 17 • **NMED Exhibit 39 – “Colorado Reg. 7”**: Colorado Regulation Number 7 - CONTROL
18 OF OZONE VIA OZONE PRECURSORS AND CONTROL OF HYDROCARBONS
19 VIA OIL AND GAS EMISSIONS (EMISSIONS OF VOLATILE ORGANIC
20 COMPOUNDS AND NITROGEN OXIDES). All citations to Colorado Reg. 7 in this
21 testimony are to Part D of that regulation unless expressly identified otherwise.

- **NMED Exhibit 40 (“Wyoming Permitting Guidance”)** – Wyoming Department of Environmental Quality, Air Quality Division – *Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance* (Revised through May 2016).

IV. REVISIONS TO MAY 6, 2021 VERSION OF PART 50

The Department has made a number of editorial and clarifying revisions to the May 6, 2021 version of proposed Part 50. The new proposed version of Part 50 with these changes to the May 6, 2021 version shown in redline strikeout format is attached as NMED Exhibit 41. The revisions address inconsistencies in verbiage, clarify terms and definitions in the definition and applicability sections of each section and throughout the rule, correct punctuation errors, and edit text to clarify the Department’s intent. The revisions to the proposed rule are explained as follows:

- 1) The term “wellhead site” is replaced with “well site” in the definition of “commencement of operation” (20.2.50.7.G); the definition “gathering and boosting station” (20.2.50.7.Q); the definition of “wellhead site” (20.2.50.7.TT); and in the other sections of Part 50 where that term appears. The new term “well site” is more consistent with the federal definition of well site. The term “wellhead” is narrowly defined in NSPS Subpart OOOOa, Section 60.5430a, and excludes equipment that the Department intended to include within the requirements of Part 50. The new terminology more accurately reflects the Department’s intent and better aligns Part 50 with other federal air quality regulations.
- 2) The term “air fuel ratio controller” (“AFRC”) is removed from the definition of “control device” at 20.2.50.7.L. The Department did not analyze AFRCs as potential control devices under Part 50, and did not intend for them to be an option for compliance with the emission standards under the rule. AFRCs are typically required when other control devices are in use, such as catalytic converters. The removal of AFRCs clarifies that the Department did

1 not analyze these types of equipment for potential application under Part 50, and did not
2 intend to include them in the definition of control device.

3 3) The definition of “gathering and booster station” in 20.2.50.7.Q is revised to clarify the
4 segment of the oil and gas industry intended to be included in this term. The new definition
5 is “a facility, including all equipment and compressors, located downstream of well sites,
6 designed to compress natural gas from well pressure to gathering system pressure prior to
7 the inlet of a natural gas processing plant.”

8 4) The definition of “natural gas compressor station” in 20.2.50.7.W is revised to add the
9 following language: “Natural gas compressor stations include transmission compressor
10 stations.” This additional language clarifies the Department’s intent to include transmission
11 compressor stations within the meaning of a natural gas compressor station.

12 5) A definition of “transmission compressor station” is added at 20.2.50.7.SS to clarify the
13 segment of the oil and gas industry included in this term, as used in the revised definition
14 of “natural gas compressor station” at 20.2.50.7.W. Under the new definition, the term
15 “transmission compressor station” means “a facility, including all equipment and
16 compressors, that moves natural gas at elevated pressure from well sites or natural gas
17 processing facilities in transmission pipelines to natural gas distribution pipelines or into
18 storage. Transmission compressor stations may include equipment for liquids separation,
19 natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.” The
20 definition of “Well Workover” is renumbered to 20.2.50.7.TT, and the definition of “Well
21 Site” is renumbered to 20.2.50.7.UU to accommodate the addition of the definition for
22 “transmission compressor station”.

- 1 6) The term “gathering and boosting sites” is replaced with “gathering and boosting stations”
2 in Section 20.2.50.111 and throughout the other sections of the rule where the term
3 “gathering and boosting sites” was used. The replacement provides consistency in the
4 terminology throughout Part 50, and aligns the language in the definitions section with the
5 remaining sections of the rule.
- 6 7) The term “transmission compressor stations” is replaced with “natural gas compressor
7 stations” in Section 20.2.50.111 and throughout the other sections of the rule where the
8 term “transmission compressor station” was used. The replacement provides consistency
9 in the terminology throughout Part 50, and aligns the language in the definitions section
10 with the remaining sections of the rule.
- 11 8) A sentence was added in Subsection B of Section 20.2.50.111 to clarify that an owner or
12 operator may not account for the effects of compliance with the requirements of Part 50 in
13 calculating the potential to emit (“PTE”) of a source for purposes of determining if the
14 source is subject to Part 50. The following sentence was added: “Owners and operators
15 may not include emissions reductions from compliance with this Part in calculating the
16 PTE of a source for purposes of this Section, or in determining whether a source is subject
17 to the requirements of this Part.”
- 18 9) A sentence was added in 20.2.50.116(A) to clarify that an owner or operator may account
19 for compliance with the requirements of Part 50 in the PTE calculations under Section
20 20.2.50.116, and in determining the monitoring frequency for a facility required in that
21 Section. The following sentence was added: “Compliance with the requirements of this
22 Part may be accounted for in determining a facility’s PTE under this Section for purposes
23 of determining applicable monitoring frequencies.”

1 10) The phrase “an artificial lift engine” in 20.2.50.117.B(3)(b) was changed to “artificial lift.”

2 This revision clarifies the Department’s intent that artificial lift is an option to comply with
3 Section 20.2.50.117.

4 11) The words “during normal operation” were added to the end of the requirement in
5 20.2.50.118.B(3)(c) to read: “still vent and flash tank emissions shall not be vented to the
6 atmosphere *during normal operation*.” (Emphasis added). The additional language
7 addresses a conflict with language in 20.2.50.118.B(3)(b) which requires owners and
8 operators using a VRU to comply with the emission standards to meet a minimum capture
9 and control efficiency of 95%. The revision addresses the conflict by clarifying under what
10 conditions venting to the atmosphere may occur, while maintaining the minimum 95%
11 emission reduction requirement.

12 12) The language in 20.2.50.120(B)(1) was revised to require owners and operators using vapor
13 balancing or vapor recovery to control emissions by 100% when transferring liquid from a
14 storage vessel to a transfer vessel, or when transferring liquid from a transfer vessel to a
15 storage vessel. The language further clarifies that the 98% control requirement applies to
16 owners and operators using a control device to comply with this emission standard when
17 transferring liquid from a storage vessel to a transfer vessel, or when transferring liquid
18 from a transfer vessel to a storage vessel.

19 13) The language in 20.2.50.120(B)(6) was revised to replace the word “prevents” with the
20 word “minimizes.” This revision clarifies the Department’s intent to have owners and
21 operators minimize emissions after a liquid leak has occurred. The revision resolves a
22 conflict in the original proposed language that was problematic because a liquid leak by
23 definition involves emissions to the atmosphere, so emissions from a liquid leak cannot be

entirely prevented, but they can be minimized in the cleaning and disposal of the leaked liquid.

14) The requirement in 20.2.50.120(C)(3) to conduct vapor testing on trucks used for hydrocarbon liquid transfers was removed. This revision clarifies the equipment and operations intended to be covered under Part 50. Tanker trucks and tanker rail cars transporting hydrocarbon liquids are not subject to Part 50 and were not analyzed by the Department during the development of the requirements in Part 50. The Department did not intend to impose testing and inspection requirements on equipment not subject to Part 50. The removal of 20.2.50.120(C)(3) also requires the deletion of the phrase “and testing” from 20.2.50.120(D)(2) and D(2)(a) through (d). This deletion is necessary in order to align the recordkeeping requirements with the revisions made to 20.2.50.120(C).

15) The colon at the end of the requirement in 20.2.50.120(D)(1) was replaced with a period to correct a drafting error.

16) The requirement in 20.2.50.122(B)(4)(c)(v) was revised to clarify that if an owner or operator meets at least a 75% total of non-emission controllers by January 1, 2025, the owner or operator is not subject to the requirements of Tables 1 and 2 of 20.2.50.122(B)(3). The phrase “has satisfied” was replaced by “is not subject to.”

17) The word “in” was deleted from the requirement in 20.2.50.123.D(2) to correct a drafting error.

V. PROPOSED RULE PROVISIONS

Section 20.2.50.1 – Issuing Agency

The Board is the issuing agency pursuant to the AQCA.

1 **Section 20.2.50.2 - Scope**

2 This section explains the areas of the State that are subject to, or may become subject to,
3 Part 50. As explained in the testimony of NMED witness Michael Baca, the Department developed
4 the proposed rule as part of its Ozone Attainment Initiative, according to the directives of the
5 AQCA at NMSA 1978, Section 74-2-5. *See* NMED Exhibit 1 at p. 4-5.

6 In accordance with the AQCA, Part 50 establishes emissions standards for oil and gas
7 production and processing sources located in areas of the State within the Board’s jurisdiction that,
8 as of the effective date of the rule or anytime thereafter, are causing or contributing to ambient
9 ozone concentrations that exceed ninety-five percent of the national ambient air quality standard
10 (“NAAQS”) for ozone, as measured by a design value calculated and based on data from one or
11 more Department monitors.¹ Those areas currently include Chaves, Eddy, Lea, Rio Arriba, San
12 Juan, Sandoval, and Valencia Counties (hereinafter referred to as the “Subject Counties”). Once a
13 source becomes subject to Part 50, the requirements of Part 50 are irrevocably effective unless the
14 source obtains a federally enforceable air permit limiting the potential to emit to below such
15 applicability thresholds established in Part 50.

16 **Section 20.2.50.3 – Statutory Authority**

17 The Environmental Improvement Board (“Board”) is authorized to adopt Part 50 pursuant
18 to the New Mexico Environmental Improvement Act (“EIA”), NMSA 1978, §§ 74-1-1 to -17, and
19 the AQCA. Section 74-1-8(A) of the EIA provides that the Board, as part of its responsibility for
20 environmental management, shall promulgate rules and standards governing air quality
21 management as provided in the AQCA (74-1-8(A)(4)), and nuisance abatement (74-1-8(A)(7)).

¹ Discussion regarding ozone monitoring in New Mexico is presented in the direct testimony of NMED witness Brent Ellington. *See* NMED Exhibit 28.

1 The Board’s statutory authority under the AQCA is addressed in the direct testimony of NMED
2 witness Michael Baca. *See* NMED Exhibit 1, at p. 4-5.

3 **Section 20.2.50.4 – Duration**

4 The Department proposes to for Part 50 to be permanently in effect from the effective date
5 established in Section 20.2.50.5.

6 **Section 20.2.50.5 – Effective Date**

7 This section establishes the date on which the regulation becomes effective and is
8 required by the New Mexico State Records Center and Archives. The effective date depends on
9 when the final regulation is published in the New Mexico Register.

10 **Section 20.2.50.6 - Objective**

11 This section identifies the purpose of Part 50 and is required by the New Mexico State
12 Records Center and Archives. The stated objective of Part 50 is “to establish emission standards
13 for volatile organic compounds (VOC) and oxides of nitrogen (NOx) for oil and gas production,
14 processing, and transmission sources.”

15 **Section 20.2.50.7 - Definitions**

16 Section 20.2.50.7 contains definitions of terms used throughout Part 50. The proposed
17 definitions are derived from state and federal regulations, and other technical glossaries used as
18 part of standard practice by the regulated community and environmental regulatory agencies.

19 Subsection A. – “Approved instrument monitoring method” means an optical gas imaging
20 (“OGI”); EPA reference method 21, 40 CFR § 60, Appendix B (NMED Exhibit 42); or other
21 instrument-based monitoring method or program approved by the Department in advance and in
22 accordance with Part 50. This definition establishes the types of monitoring methods that may be

used to monitor fugitive emissions and that are approved or may be approved by the Department.
This definition was derived from Colorado Reg. 7, Section I.L.8.

Subsection B. – “Auto-igniter” means a device that automatically attempts to relight the pilot flame in the combustion chamber of a control device in order to combust VOC emissions, or a device that will automatically attempt to combust the VOC emission stream. This definition was derived in part from Colorado Reg. 7, Section I.B.5.

Subsection C. – “Bleed rate” means the rate in standard cubic feet per hour at which natural gas is continuously or intermittently vented from a pneumatic controller. This definition was derived in part from NSPS Subpart OOOOa, 40 CFR § 60.5430a.

Subsection D. – “Calendar year” means a year beginning January 1 and ending December 31. This definition implements the commonly accepted interpretation of a calendar year.

Subsection E. – “Centrifugal compressor” means a machine used for raising the pressure of natural gas by drawing in low-pressure natural gas and discharging significantly higher-pressure natural gas by means of a mechanical rotating vane or impeller. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors. This definition was derived in part from NSPS Subpart OOOOa, 40 CFR § 60.5430a.

Subsection F. – “Closed vent system” means a system that is designed, operated, and maintained to route the VOC emissions from a source or process to a process stream or control device with no loss of VOC emissions to the atmosphere. This definition was derived in part from language in Colorado Reg. 7, Section I.J, and NSPS Subpart OOOOa, 40 CFR § 60.5411a(a).

Subsection G. – “Commencement of operation” means for an oil and natural gas wellhead, the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage vessels from the first producing well at the stationary source, but

1 no later than the end of well completion operation. This definition describes when operation of a
2 production well may be presumed to have begun and was derived in part from Colorado Reg. 7,
3 Section I.B.7.

4 Subsection H. – “Component” means a pump seal, flange, pressure relief device (including
5 thief hatch or other opening on a storage vessel), connector or valve that contains or contacts a
6 process stream with hydrocarbons, except for components where process streams consist solely of
7 glycol, amine, produced water or methanol. This definition was derived in part from Colorado
8 Reg. 7, Section I.B.10.

9 Subsection I – “Connector” means flanged, screwed, or other joined fittings used to connect
10 pipe line segments, tubing, pipe components (such as elbows, reducers, “T’s” or valves) to each
11 other; or a pipe line to a piece of equipment; or an instrument to a pipe, tube, or piece of equipment.
12 A common connector is a flange. Joined fittings welded completely around the circumference of
13 the interface are not considered connectors for the purpose of this Part. This definition was derived
14 in part from Colorado Reg. 7, Section I.B.11.

15 Subsection J. – “Construction” means fabrication, erection, installation or relocation of a
16 stationary source, including but not limited to temporary installations and portable stationary
17 sources. This definition describes the types of activities that constitute construction and was taken
18 from the Board’s regulations at 20.2.72 NMAC – *Construction Permits*.

19 Subsection K. – “Custody transfer” means the transfer of oil or natural gas after processing
20 or treatment in the producing operation, or from a storage vessel or automatic transfer facility or
21 other processing or treatment equipment including product loading racks, to a pipeline or any other
22 form of transportation. This definition describes the concept of custody transfer and was derived
23 in part from Colorado Reg. 7, Part B, Section IV.A.2.c.

1 Subsection L. – “Control device” means air pollution control equipment or emission
2 reduction technologies that thermally combust, chemically convert, or otherwise destroy or recover
3 air contaminants. Examples of control devices include but are not limited to open flares, enclosed
4 combustion devices (“ECDs”), thermal oxidizers (“TOs”), vapor recovery units (“VRUs”), fuel
5 cells, condensers, air fuel ratio controllers (“AFRs”), catalytic converters (oxidative, selective, and
6 non-selective), or other emission reduction equipment. A control device may also include any other
7 air pollution control equipment or emission reduction technologies approved by the department to
8 comply with emission standards in this Part. This definition was derived in part from Colorado
9 Reg. 7, Part A, Section II.A.7.

10 Subsection M. – “Department” means the New Mexico Environment Department.

11 Subsection N. – “Downtime” means the period of time when equipment is not in operation,
12 or when a well is producing, and the control device is not in operation. This definition was derived
13 in part from Merriam-Webster dictionary.

14 Subsection O. – “Enclosed combustion device” or “ECD” means a combustion device
15 where gaseous fuel is combusted in an enclosed chamber. This may include, but is not limited to
16 an enclosed flare, reboiler, and heater. This definition describes the types of equipment that are
17 considered ECDs and the theory of ECD operation. Enclosed combustion device is a common term
18 used in oil and gas regulatory provisions. *See, e.g.*, NSPS Subpart OOOOa, 40 CFR §
19 60.5412(d)(1). The definition in Part 50 was developed during rule drafting based on the
20 knowledge and experience of NMED technical staff.

21 Subsection P. – “Existing” means constructed or reconstructed before the effective date of
22 this Part and has not since been modified or reconstructed. This definition is required because the

1 applicability of numerous requirements and timeframes in Part 50 is based on whether a source is
2 “existing” or “new”.

3 Subsection Q. – “Gathering and boosting station” means a facility, including all equipment
4 and compressors, located downstream of well sites, designed to compress natural gas from well
5 pressure to gathering system pressure prior to the inlet of a natural gas processing plant. This
6 definition was derived in part from NSPS Subpart OOOOa, 40 CFR § 60.5430a.

7 Subsection R. – “Glycol dehydrator” means a device in which a liquid glycol absorbent,
8 including ethylene glycol, diethylene glycol, or triethylene glycol, directly contacts a natural gas
9 stream and absorbs water. This definition was derived in part from Colorado Reg. 7, Section
10 I.B.15.

11 Subsection S. – “Hydrocarbon liquid” means any naturally occurring, unrefined petroleum
12 liquid and can include oil, condensate, and intermediate hydrocarbons. This definition was derived
13 in part from Colorado Reg. 7, Section I.B.16.

14 Subsection T. – “Liquid unloading” means the removal of accumulated liquid from the
15 wellbore that reduces or stops natural gas production. This definition derived from general
16 information on EPA’s Natural Gas STAR website and the EPA publication “Options for Removing
17 Accumulated Fluid and Improving Flow in Gas Wells” (NMED Exhibit 44).

18 Subsection U. – “Liquid transfer” means the loading and unloading of a hydrocarbon liquid
19 or produced water between a storage vessel and tanker truck or tanker rail car for transport. This
20 definition was derived from general information from EPA’s website and EPA’s AP-42 Chapter
21 5.2 Transportation and Marketing of Petroleum Liquids, Section 5.2.2 (NMED Exhibit 43).

22 Subsection V. – “Local distribution company custody transfer station” means a metering
23 station where the local distribution (“LDC”) company receives a natural gas supply from an

1 upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer,
2 for delivery to customers through the LDC's intrastate transmission or distribution lines. This
3 definition was derived from NSPS Subpart OOOOa, 40 CFR § 60.5430a.

4 Subsection W. – “Natural gas compressor station” means a facility, including all equipment
5 and compressors, designed to compress natural gas from well pressure to gathering system
6 pressure before the inlet of a natural gas processing plant, or to move compressed natural gas
7 through a transmission pipeline. Natural gas compressor stations include transmission compressor
8 stations. This definition was derived in part from Colorado Reg. 7, Section I.B.19, and the EPA
9 CTG, Section C.7.

10 Subsection X. – “Natural gas-fired heater” means an enclosed device using a controlled
11 flame and with a primary purpose to transfer heat directly to a process material or to a heat transfer
12 material for use in a process. This definition was derived in part from Colorado Reg. 7., Part E,
13 section II.A.3.p.

14 Subsection Y. – “Natural gas processing plant” means the processing equipment engaged
15 in the extraction of natural gas liquid from natural gas or fractionation of mixed natural gas liquid
16 to a natural gas product, or both. A Joule-Thompson valve, a dew point depression valve, or an
17 isolated or standalone Joule-Thompson skid is not a natural gas processing plant. This definition
18 was derived from the NSPS Subpart OOOOa, 40 CFR § 60.5430a.

19 Subsection Z. – “New” means constructed or reconstructed on or after the effective date of
20 this Part. This definition is required because the applicability of numerous requirements and
21 timeframes in Part 50 is based on whether a source is “existing” or “new”.

1 Subsection AA. – “Operator” means the person or persons responsible for the overall
2 operation of a stationary source. The definition was derived in part from the CAA at 42 U.S.C
3 Section 7411.

4 Subsection BB. – “Optical gas imaging” or (“OGI”) means an imaging technology that
5 utilizes a high-sensitivity infrared camera designed for and capable of detecting hydrocarbons.
6 This definition was derived in part from Colorado Reg. 7, Section I.B.17, and NSPS Subpart
7 OOOOa, 40 CFR § 60.5397a.

8 Subsection CC. – “Owner” means the person or persons who own a stationary source or
9 part of a stationary source. This definition was derived in part from the CAA at 42 U.S.C Section
10 7411.

11 Subsection DD. – “Permanent pit” means a pit used for collection, retention, or storage of
12 produced water or brine and is installed for longer than one year. This definition was derived in
13 part from the New Mexico Oil Conservation Commission’s (“OCC”) regulations at 19.15.17
14 NMAC.

15 Subsection EE. – “Pneumatic controller” means an instrument that is actuated using
16 pressurized gas and used to control or monitor process parameters such as liquid level, gas level,
17 pressure, valve position, liquid flow, gas flow, and temperature. The definition was derived in part
18 from Colorado Reg. 7, Section III.B.10.

19 Subsection FF. – “Pneumatic diaphragm pump” means a positive displacement pump
20 powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in
21 conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston
22 driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that

1 relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm
2 pump. This definition was derived in part from NSPS Subpart OOOOa, 40 CFR § 60.5430a.

3 Subsection GG. – “Potential to emit” or (“PTE”) means the maximum capacity of a
4 stationary source to emit an air contaminant under its physical and operational design. The physical
5 or operational limitation on the capacity of a source to emit an air pollutant, including air pollution
6 control equipment and a restriction on the hours of operation or on the type or amount of material
7 combusted, stored or processed, shall be treated as part of its design if the limitation is federally
8 enforceable. The PTE for nitrogen dioxide shall be based on total oxides of nitrogen. This
9 definition was derived from the Board’s air quality operating permit regulations at 20.2.70 NMAC.

10 Subsection HH. – “Produced water” means a fluid that is an incidental byproduct from
11 drilling for or the production of oil and gas. This definition describes what is meant by the term
12 produced water and was derived from the OCC’s regulations at 19.15.2 NMAC.

13 Subsection II. – “Produced water management unit” means a recycling facility or a
14 permanent pit that is a natural topographical depression, man-made excavation, or diked area
15 formed primarily of earthen materials (although it may be lined with man-made materials), which
16 is designed to accumulate produced water and has a design storage capacity equal to or greater
17 than 50,000 barrels. This definition describes what is meant by the term produced water
18 management unit and was derived in part from the OCC’s regulations at 19.15.2, 19.15.17, and
19 19.15.34 NMAC.

20 Subsection JJ. – “Qualified Professional Engineer” means an individual who is licensed by
21 a state as a professional engineer to practice one or more disciplines of engineering and who is
22 qualified by education, technical knowledge, and experience to make the specific technical

1 certifications required under this Part. This definition was derived in part from NSPS Subpart
2 OOOOa, 40 CFR § 60.5430a.

3 Subsection KK. – “Reciprocating compressor” means a piece of equipment that increases
4 the pressure of process gas by positive displacement, employing linear movement of a piston rod.
5 This definition was derived from Colorado Reg. 7, Section I.B.24.

6 Subsection LL. – “Reconstruction” means a modification that results in the replacement of
7 the components or addition of integrally related equipment to an existing source, to such an extent
8 that the fixed capital cost of the new components or equipment exceeds fifty percent of the fixed
9 capital cost that would be required to construct a comparable entirely new facility. This definition
10 was derived from the Board’s regulations at 20.2.72 NMAC.

11 Subsection MM. – “Recycling facility” means a stationary or portable facility used
12 exclusively for the treatment, re-use, or recycling of produced water and does not include oilfield
13 equipment such as separators, heater treaters, and scrubbers in which produced water may be used.
14 This definition was derived from the OCC’s regulations at 19.15.34 NMAC.

15 Subsection NN. – “Responsible official” means one of the following: (1) for a corporation:
16 president, secretary, treasurer, or vice-president of the corporation in charge of a principal business
17 function, or any other person who performs similar policy or decision-making functions for the
18 corporation, or a duly authorized representative of the corporation if the representative is
19 responsible for the overall operation of the source, or (2) for a partnership or sole proprietorship:
20 a general partner or the proprietor, respectively. This definition was derived from the Board’s
21 operating permit regulations at 20.2.70 NMAC.

22 Subsection OO. – “Small business facility” means, for the purposes of this Part, a source
23 that is independently owned or operated by a company that is not a subsidiary or a division of

1 another business, that employs no more than employees at any time during the calendar year, and
2 that has a gross annual revenue of less than \$250,000. Employees include part-time, temporary, or
3 limited service workers. This definition was developed during rule drafting by NMED technical
4 staff and contractors. An in-depth discussion of the basis for this definition is provided in the
5 testimony of NMED witnesses Elizabeth Bisbey-Kuehn and Susan Day.

6 Subsection PP. – “Startup” means the setting into operation of air pollution control
7 equipment or process equipment. This definition was derived from the Board’s regulations at
8 20.2.7 NMAC – *Excess Emissions*.

9 Subsection QQ. – “Stationary Source” or "source" means any building, structure,
10 equipment, facility, installation (including temporary installations), operation, process, or portable
11 stationary source that emits or may emit any air contaminant. Portable stationary source means a
12 source that can be relocated to another operating site with limited dismantling and reassembly.
13 This definition was derived from the Board’s air quality construction permit regulations at 20.2.72
14 NMAC.

15 Subsection RR. – “Storage vessel” means a single tank or other vessel that is designed to
16 contain an accumulation of hydrocarbon liquid or produced water and is constructed primarily of
17 non-earthen material including wood, concrete, steel, fiberglass, or plastic, which provide
18 structural support, or a process vessel such as a surge control vessel, bottom receiver, or knockout
19 vessel. A well completion vessel that receives recovered liquid from a well after commencement
20 of operation for a period that exceeds 60 days is considered a storage vessel. A storage vessel does
21 not include a vessel that is skid-mounted or permanently attached to a mobile source and located
22 at the site for less than 180 consecutive days, such as a truck railcar, or a pressure vessel designed
23 to operate in excess of 204.9 1 kilopascals without emissions to the atmosphere. This definition

describes was derived in part from Colorado Reg. 7, Section I.B.27, and NSPS Subpart OOOOa, 40 CFR § 60.5365a.

Subsection SS. – “Transmission Compressor Station” means a facility, including all equipment and compressors, that moves natural gas at elevated pressure from well sites or natural gas processing facilities in transmission pipelines to natural gas distribution pipelines or into storage. Transmission compressor stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.

Subsection TT. – “Well workover” means the repair or stimulation of an existing production well for the purpose of restoring, prolonging, or enhancing the production of hydrocarbons. This definition was derived from the MAP report.

Subsection UU. – “Wellhead site” means the equipment directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. A wellhead site may include equipment used for extraction, collection, routing, storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and product piping. This definition was derived from Colorado Reg. 7, Section I.B.30, and NSPS Subpart OOOOa, 40 CFR § 60.5430a.

Section 20.2.50.111 - Applicability

Subsection A of Section 20.2.50.111 outlines the specific sources of air pollutants that are covered under Part 50. The rule applies to crude oil and natural gas production and processing equipment, including equipment and operations that extract, collect, separate, dehydrate, store, process, transport, transmit, handle hydrocarbon liquids or produced water in areas of the state specified in Section 20.2.50.2 and located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations located up to the point

1 of the local distribution company custody transfer station. Part 50 applies to state, federal, and
2 privately owned land, but does not apply to tribal lands or Bernalillo County.

3 Subsection B of Section 20.2.50.111 specifies how to determine whether a source is subject
4 to Part 50; specifically, owners and operators must calculate the PTE of each potentially affected
5 source to determine if it is subject to requirements under the rule. The PTE calculation must be
6 certified by a qualified profession engineer. This certification is critical to ensuring the potential
7 air emissions from equipment and processes are properly calculated and representative of the
8 source, and present a true and accurate representation of the source's potential emissions. Without
9 this certification, emission calculations may be performed based on process, emission, or
10 operational inputs that are not accurate or representative, which then underestimate the true
11 potential emissions and result in a determination that equipment is not subject to this part. The
12 PTE calculation is the foundation of determining applicability of this part and the certification of
13 the PTE calculation ensures the integrity of how that fundamental calculation is performed.

14 Subsection C of Section 20.2.50.111 provides that owners and operators of small business
15 facilities as defined in 20.2.50.7.OO are subject to the requirements of Section 20.2.50.125. A full
16 discussion of Section 20.2.50.125

17 Subsection D of Section 20.2.50.111 provides that petroleum refiners and transmission
18 pipelines are not subject to Part 50.

19 **Section 20.2.50.112 – General Provisions**

20 General Requirements

21 Subsection A of Section 20.2.50.112 outlines general provisions that establish a universal
22 set of requirements applicable to all owners and operators of sources of emissions subject to
23 emissions standards and other requirements of Part 50. Owners and operators of all affected

1 sources must meet the general operational, monitoring, recordkeeping, and reporting requirements
2 set forth in Subsection A.

3 Paragraph (1) of Subsection (A) establishes work practice standards requiring equipment
4 to be operated consistent with manufacturer specifications, for those specifications to be kept on
5 file. For older equipment, it is often the case that equipment specifications provided by the
6 equipment manufacturer is outdated, cannot be located, or in some cases does not exist. Thus, for
7 equipment constructed prior to 1980 for which there is no manufacturer specification, NMED
8 requires owners and operators to develop and follow a maintenance schedule sufficient to operate
9 and maintain the sources in good working order.

10 Paragraph (2) of Subsection A establishes a requirement that equipment be operated a
11 manner that minimizes emissions of air contaminants, including NOx and VOC. This is a standard
12 operational requirement intended to ensure that equipment is used for its intended purpose only;
13 that equipment is maintained in good working order such that it operates within its normal
14 operating parameters, loads, and process and throughput rates; and that owners and operators
15 proactively address any operational issues to avoid excess emissions due to equipment failures,
16 malfunctions, or lack of proper maintenance and operation.

17 Paragraphs (3) through (9) of Subsection A establishes requirements for owners and
18 operators to install an Equipment Monitoring Tag (“EMT”) on certain equipment. The EMT is a
19 tag that interacts with a company’s equipment database and is used to track equipment information
20 and compliance monitoring events and data. This section outlines what equipment data and
21 compliance monitoring information are required to be maintained for each source subject to Part
22 50. The EMT is required to be scanned by owners and operators prior to compliance monitoring
23 events, which certifies that owners and operators have initiated a compliance event. After the

1 compliance monitoring event concludes, owners and operators must complete a final scan of the
2 EMT, which concludes event. The data required to be maintained includes a unique identification
3 number, location, source type, the potential to emit; make, model, serial number; and a link to the
4 manufacturer's maintenance and repair schedule. This section also outlines the general
5 requirements for maintaining and operating the EMT; requirements for the owner and operator to
6 manage the sources' record of data in a database that can generate a compliance database report in
7 a format determined by the department; requirements to contemporaneously track compliance
8 events for each subject source and requirements for timely uploads of monitoring or testing event
9 data; and requirements for maintaining those records for a period of at least five years.

10 The EMT requirements will significantly improve the Department's ability to receive,
11 review, and analyze compliance monitoring data for subject sources. In addition, these
12 requirements will help improve and increase the public's confidence that required compliance
13 monitoring is in fact occurring as required, because the contemporaneous scanning and
14 recordkeeping during the monitoring and testing events ensures that owners and operators are
15 fulfilling the monitoring requirements of the rule.

16 Paragraph (10) of Subsection A establishes a requirement for owners and operators to retain
17 a third party at their own expense to verify any information collected, reported, or recorded
18 pursuant to Part 50, if requested by the Department. The third party must conduct an assessment
19 and make recommendations to correct or improve the data collected. The owner or operator is
20 required to share the third party assessment and recommendations with the Department and
21 implement them in a manner approved by the Department. The third-party compliance verification
22 requirement provides a critical new auditing option if the Department suspects or finds that an
23 owner or operator is failing to meet requirements under Part 50. Such verification will benefit the

1 Department's compliance program in significant ways. Having a compliance assessment
2 conducted and a report prepared by an outside third party results in a considerable time and
3 resource savings for the Department, which already operates under limited staffing and financial
4 resources. The Department can review the compliance assessment report highlighting any issues
5 and recommendations, and approve is the manner in which the recommendations are implemented.
6 This approach will improve and increase the public's confidence in the company's compliance
7 with Part 50. In sum, the ability of the Department to require a third-party compliance audit
8 strengthens the overall rule; saves limited staffing resources; improves the public's confidence in
9 compliance with the rule; will result in overall better compliance; and provides owners and
10 operators with targeted recommendations on how to improve any compliance issues identified in
11 the report.

12 General Monitoring Requirements

13 Subsection B of 20.2.50.112 specifies general monitoring requirements for sources subject
14 to Part 50. Monitoring of equipment, processes, and emissions provides owners and operators with
15 information they can use to evaluate the equipment operation and performance relative to the
16 requirements of the rule, and assist them in determining proper corrective actions when necessary.
17 Equipment monitoring provides the basis for most on-going compliance demonstrations and
18 provides documentation to support the required compliance certification. The provisions in
19 Subsection B establish a monthly inspection requirement for sources subject to emissions
20 standards and monitoring under Part 50; a process for submitting an alternative monitoring strategy
21 for the Department's consideration; and requirements for EMT scanning and reporting of certain
22 required data and information obtained during the monitoring event.

1 Paragraph (1) of Subsection (B) requires owners and operators to inspect affected sources
2 at least monthly to ensure proper operation and maintenance of such sources, unless a different
3 schedule is specified under another Section of Part 50. This monthly inspection is the minimum
4 periodic monitoring requirement for sources subject to Part 50 and requires owners and operators
5 to evaluate the overall operation of the source. There are different types of source monitoring
6 required under the other sections of the rule, and this requirement establishes the baseline monthly
7 inspection. In the source-specific subparts, additional types of monitoring, including parametric
8 monitoring, emissions stack testing, and other types of inspections are required.

9 Paragraph (2) of Subsection (b) provides a process by which owners and operators can
10 propose an equally effective, enforceable, and equivalent alternative monitoring strategy to the
11 Department for consideration. This is a critical option for both the Department and affected owners
12 and operators, as it provides a process by which new and innovative monitoring approaches and
13 technologies can be used to comply with the monitoring requirements of Part 50. As new
14 monitoring technology becomes available and technically feasible, it is important for operators to
15 have flexibility in the performance of compliance monitoring required under the rule. For instance,
16 fence line air monitoring and aerial surveillance technologies are quickly evolving and both
17 approaches can improve real time emissions data collection and enable faster compliance
18 assessments covering multiple sources.

19 An alternative monitoring strategy must first be reviewed and approved in writing by the
20 Department prior to implementation. The Department will provide an alternative monitoring
21 strategy request form, which will outline the criteria for demonstrating that the proposed
22 alternative meets the requirements of the rule that it be equally effective, enforceable, and
23 equivalent. At a minimum, the proposal must effectively monitor the source for the pollutants of

1 concern and establish sufficient monitoring, recordkeeping, and reporting requirements such that
2 the requirements are legally and practically enforceable.

3 Paragraph (3) of Subsection B provides that monitoring events for equipment required to
4 have an EMT must be initiated and completed by scanning the unit's EMT. As previously
5 discussed, requiring an affirmative scanning of the EMT prior to and after the conclusion of any
6 monitoring event provides assurance that the monitoring event actually occurred and will reduce
7 the incidences of missed compliance monitoring requirements and inaccurate monitoring records.
8 The minimum set of data required to be uploaded to the company database includes: the date and
9 time of the monitoring event, name of the personnel conducting the event, ID and type of unit,
10 description of any maintenance or repair conducted, and the results of the event as required under
11 Part 50.

12 General Recordkeeping Requirements

13 Subsection C of Section 20.2.50.112 establishes minimum universal recordkeeping
14 requirements that owners and operators of sources subject to Part 50 must comply with. These
15 include a requirement to upload monitoring data within three business days of any monitoring
16 event; to maintain all records required under this part for at least five years; and to complete a full
17 compliance evaluation of sources subject to this part prior to any transfer of ownership.

18 The requirement for a full compliance evaluation prior to any transfer of ownership will
19 have significant and positive benefits for public health and the environment, as well as for the
20 Department and its air compliance program. This requirement obligates owners and operators to
21 conduct and document a full evaluation of all affected sources' compliance with the full
22 requirements of Part 50. The documentation must include a certification by a responsible official
23 as to the compliance status of all affected sources with respect to the emission standards,

1 monitoring, recordkeeping, and reporting requirements of Part 50. The compliance evaluation
2 must be conducted at least three months prior to any transfer of ownership, and the documentation
3 must be kept by the new owner or operator for at least five years. This provision is important as it
4 requires owners and operators to perform a preemptive compliance determination, which can
5 highlight potential compliance issues for the current owner, future owner, and the Department.
6 The report will also provide important compliance status information to the Department, which
7 may be used in the development of enforcement cases and can provide a compliance baseline from
8 which to reference and compare the new owner's compliance progress and improvement, or
9 decline.

10 General Reporting Requirements

11 Subsection D of Section 20.2.50.111 establishes general reporting requirements for
12 sources subject to Part 50. Owners and operators are required to make any reports required to be
13 generated under Part 50 available to the Department within 24 hours of the Department's
14 request. Those reports must be made available in an electronic format and submitted to the
15 Department's secure extranet portal or by other means or formats as specified by the
16 Department.

17 **Section 20.2.50.113 – Engines and Turbines**

18 Section 20.2.50.113 applies to portable and stationary natural gas-fired spark ignition
19 engines; compression ignition engines; and natural gas-fired combustion turbines located at well
20 sites, tank batteries, gathering and boosting stations, natural gas processing plants, and natural
21 gas compressor stations with a rated horsepower greater than those shown in Tables 1, 2, and 3
22 of Section 113.

1 Description of Equipment and Process

2 Engines and turbines are used in the oil and gas industry to power compressors that
3 maintain natural gas pressures at levels sufficient to move gas through gathering and
4 transmission pipelines. Compressors at gathering compressor stations move the gas from the
5 wellhead to gas processing plants. Compressors at gas processing plants move the gas from the
6 processing plants to transmission pipelines, and compressors at transmission compressor stations
7 maintain pressure and move the gas along the transmission pipelines to the ultimate user of the
8 processed gas.

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

15 Two kinds of reciprocating internal combustion engines are used in the oil and gas
16 industry: spark ignition and compression ignition. In a spark ignition engine, fuel mixes with air
17 and is introduced during the intake process. After compression of the fuel-air mixture, it is
18 ignited by a spark from a spark plug to cause combustion. The combustion gases expand and
19 push the piston during the power stroke. In compression ignition engines, typically diesel, only
20 air is inducted into the engine then highly compressed. Fuel is injected or sprayed into the hot,
21 compressed air, causing it to ignite without the need for an external spark.

22 The work cycle of both types of engines may either be two-stroke or four-stroke. A four-
23 stroke spark ignition engine consists of the following: the suction or intake stroke, compression

1 stroke, combustion and power stroke, and exhaust stroke, each consisting of 180 degrees of
2 crankshaft rotation. A two-stroke cycle completes its power cycle with only two strokes of the
3 piston. In a two-stroke engine, the end of the combustion stroke and the beginning of the
4 compression stroke occur simultaneously, with the intake and exhaust occurring at the same
5 time. Reciprocating internal combustion engines are generally used to power reciprocating
6 compressors, and often the engine and compressor share the same crankshaft in what is known as
7 an integral compressor.

8 A combustion turbine consists of an upstream rotating combustion gas compressor, a
9 combustor, and a downstream turbine on the same shaft as the combustion gas compressor.
10 During operation, the combustion turbine compresses atmospheric air and mixes it with fuel that
11 is burned at extremely high temperatures, creating a hot gas. This hot mixture moves through
12 blades in the turbine, causing them to spin quickly. These blades rotate the turbine drive shaft,
13 which powers the combustion gas compressor.

14 Control Options

15 *Control Options for NO_x – Engines*

16 Readily available options for controlling NO_x on two-stroke and four stroke lean burn²
17 engines include low emissions controls, selective catalytic reduction, and non-selective catalytic
18 reduction.

19 Low Emissions Controls (“LEC”)³ is a NO_x emissions reduction method that can be
20 retrofitted on most fuel injected two-stroke lean burn engines. NO_x emissions increase with

² The difference between a rich-burn or lean-burn engine lies in the air-to-fuel ratio. A rich-burn engine has excess fuel in the combustion chamber, while a lean-burn engine has excess air in the combustion chamber.

³ LEC consist of a combination of combustion controls in which various engine modifications, upgrades, and tuning methods result in lower combustion emissions. One upgrade includes increasing the air-to-fuel (AFR) ratio to reduce thermal NO_x formation by diluting combustion gases and lowering peak flame temperature, that would require upgrades to the AFR controller and turbocharger (a device that increases an engine’s power output by forcing extra compressed air - and proportionally more fuel - into the combustion chamber). Another modification associated with

1 higher combustion temperature. LEC engine retrofit modifications reduce NO_x by adding excess
2 air in the combustion zone to reduce combustion temperature, thereby reducing NO_x emissions.
3 This change in the air-to-fuel ratio may require other changes to an engine's combustion process.
4 Variation in the amount of NO_x emission reduction, required modifications, and cost will depend
5 on the make, model, and vintage of the engine.

6 Selective catalytic reduction ("SCR") is a post-combustion NO_x control for lean-burn
7 engines that utilizes a catalyst and a reducing agent to reduce the concentration of NO_x in the
8 exiting combustion gas. The reagent, typically ammonia or urea is injected into the exhaust
9 stream of the engine where the ammonia (or urea, that decomposes to produce ammonia in the
10 exhaust stream) passes over a catalyst and combines with oxygen to enhance the conversion of
11 NO_x and ammonia into nitrogen and water. An oxidation catalyst must be added to the SCR
12 design if hydrocarbons and carbon monoxide need to be controlled in addition to NO_x on a lean-
13 burn engine. Oxidation catalysts consist of precious metals, such as platinum, palladium or
14 rhodium, or metal oxides containing chlorinated compounds, impregnated on high surface area
15 carriers (e.g., a honeycomb structure referred to as a catalyst bed) placed in the exhaust stream.
16 An oxidation catalyst promotes the oxidation of CO and hydrocarbons (HCs) to carbon dioxide
17 and water as the gas stream passes through the catalyst bed. The CO₂, water, and NO_x then enter
18 the SCR catalyst where the NO_x reacts with the ammonia.

19 Catalyst selection is partly based on the expected range of the engine exhaust, and is
20 sized to achieve the desired amount of NO_x reduction. The reagent injection system is comprised

LEC is adjusting ignition timing to delay ignition in the power stroke when the chamber is below its maximum pressure. This results in ignition at a lower temperature and lower thermal NO_x formation during combustion. Other LEC options include installing cylinder heads fitted with pre-combustion chambers (a space in which combustion gases are ignited a combustion commenced ahead of the main combustion chamber, resulting in complete combustion of the fuel), larger intercooling applications, and enhanced mixing of air and fuel.

1 of a storage tank, reagent injector(s), reagent pump, pressure regulator and electronic controls to
2 accurately meter the quantity of reagent injected as a function of engine load, speed, temperature,
3 and NOx emissions. The Ozone Transport Commission's⁴ final technical document, *Technical*
4 *Information - Oil and Gas Sector – Significant Stationary Sources of NOx Emissions* (October
5 17, 2012) (NMED Exhibit 45),⁵ indicates that NOx reductions of up to 95% may be achieved
6 using SCR. The energy and non-air environmental impacts should be evaluated on a case-by-
7 case basis to determine the suitability of SCR. SCR requires ammonia and catalyst replacements,
8 generating waste that must be disposed of, and there is some increase in electric input to operate
9 the system. SCR systems also emit unreacted ammonia in the process, referred to as ammonia
10 slip. This ammonia can combine with sulfur dioxide and nitrogen oxides in the atmosphere to
11 form ammonium sulfate and ammonium nitrate as fine particulate matter.

12 Non-selective catalytic reduction ("NSCR"), or three-way catalyst, is a potential control
13 option for reducing NOx, CO, and VOC emissions from rich burn engines. Exhaust from the
14 engine is passed through a metallic or ceramic honeycomb covered with a platinum group metal
15 catalyst. The catalyst promotes the low temperature (approximately 850°F) reduction of NO_x
16 into N₂, the oxidation of CO into CO₂, and the oxidation of VOCs into water and CO₂. The
17 catalyst efficiency is directly related to the air/fuel mixture and temperature of the exhaust. To
18 maintain the proper exhaust gas oxygen concentration across the operating range of the engine,
19 an air/fuel ratio controller⁶ must be installed for varying engine load, engine speed conditions,
20 and varying ambient conditions. See NMED Exhibit 45 at p. 32.

⁴ The Ozone Transport Commission is a multi-state organization created under the CAA that develops regional solutions for ozone in the Northeast and mid-Atlantic states.

⁵ Available at:

<https://otcair.org/upload/Documents/Meeting%20Materials/Final%20Oil%20%20Gas%20Sector%20TSD%2010-17-12.pdf>

⁶ Air fuel ratio controllers-To obtain the proper exhaust gas O₂ across the operating range, an air/fuel ratio controller is installed that measures the oxygen concentration in the exhaust and adjusts the inlet air/fuel ratio to meet the

1 *Control Options for NO_x – Turbines*

2 Readily available NO_x control options for turbines include water or steam injection, dry
3 low-NO_x burners, and SCR.

4 Water or steam injection involves injecting water into the combustion zone of a turbine to
5 lower peak flame temperatures, which subsequently lowers the amount of thermal NO_x
6 formation during combustion. Water may be injected directly into the turbine combustor or may
7 be converted to steam using waste heat recovered from turbine exhaust with a heat recovery
8 steam generator, and then injected into the combustor as steam. More steam than water is
9 required to achieve a comparable reduction of NO_x. *See* NMED Exhibit 45 at p. 62.

10 Dry Low NO_x Burners (“DLNB”), also referred to as improved combustion technology,
11 reduce the peak flame temperature and residence time of fuel in the combustor, thereby reducing
12 thermal NO_x formation by increasing the air-to-fuel ratio in the combustion chamber. Not all
13 turbine designs can accommodate a DLNB, and this technology may not be available for all
14 makes and models of combustion turbines. In addition to the replacement of the turbine’s
15 combustors, the installation of this technology may require modifications or replacement of
16 associated piping and turbine control modification or replacement.

17 SCR technology, described above, is also a potential control option for turbines.

18 *Control Options for VOC – Engines*

19 Readily available VOC control options for engines include NSCR and catalytic oxidation.
20 The control of VOCs using NSCR for rich burn engines to control CO and VOC, as well as NO_x,
21 is explained above in the discussion of using NSCR for NO_x control. The use of catalytic

proper 0.5% O₂ exhaust requirement for varying engine load conditions, engine speed conditions, and ambient conditions.

1 oxidation for VOC and CO emissions control for lean burn engines is explained above in the
2 discussion of SCR systems for lean burn engines.

3 *Control Options for VOC – Turbines*

4 A readily available VOC control option for turbines is catalytic oxidation. The control of
5 VOCs using catalytic oxidation is explained above under the control options for VOC from
6 engines.

7 Proposed Rule Requirements

8 Section 20.2.50.113 requires owners and operators of new and existing portable and
9 stationary engines and turbines equal to or exceeding specified horsepower ratings to meet NOx,
10 CO, and VOC emission limits.

11 For existing spark ignited engines, owners and operators are required to develop an
12 inventory of those engines and meet the emission limits over a specified timeline. This timeline
13 requires a certain percentage of the inventoried fleet to meet the requirements by specified
14 deadlines. The timeline allows owners and operators sufficient time to come into compliance
15 with the requirements of this subpart. In lieu of meeting the emissions limits, owners and
16 operators may reduce the number of hours of operation in order to reduce emissions to rates
17 similar to the emissions reduction requirements achieved by utilizing emission control devices.
18 This option provides an alternative method of compliance for engines that are difficult to retrofit,
19 while ensuring equivalent emission reductions.

20 New spark ignited engines must meet the emission limits upon startup. New and existing
21 compression ignited engines must meet specified emission limitations depending upon the
22 construction date of the units. New and existing turbines must meet specified emission
23 limitations depending upon the construction date of the units. Owners and operators are required

1 to meet the minimum recommended maintenance schedule; document when those units are taken
2 out of service for more than two hours; operate emission control devices per the manufacturer
3 specifications; perform initial and annual emissions testing; monitor the hours of operation for
4 certain units; and install an EMT on all units subject to this subpart. Owners and operators are
5 required to maintain records of certain information on units subject to this Section, including the
6 make, model, and serial number; a copy of the engine, turbine, and control device manufacturer
7 specifications; information on the initial and annual emissions testing; hours of operation; and
8 information documenting that emissions reductions realized through the reduction in hours of
9 operation is equivalent to a 95% reduction in NOx and VOC emissions. Owners and operators
10 are required to report in accordance with the requirements of Section 20.2.50.112.

11 Basis for Proposed Regulatory Requirements

12 *Natural Gas-Fired Spark-Ignition Engines*

13 The proposed NOx limit of 0.50 grams per brake horsepower per hour (g/bhp-hr) for
14 existing lean burn engines greater than 1,000 bhp is based on the use of low emission
15 combustion retrofit on existing engines, or the addition of a SCR control system.

16 This is the same limit as that used in Section C of Pennsylvania GP-5 for natural gas-fired
17 spark ignition engines greater than 500 hp authorized to operate on or after February 2, 2013. A
18 less stringent standard (2.0 g/bhp-hr) applies to all spark ignition engines authorized to operate
19 between March 10, 1997, and February 2, 2013. A more stringent standard (0.30 g/bhp-hr)
20 applies to engines greater than or equal to 2,370 hp authorized to operate on or after August 8,
21 2018. *See* NMED Exhibit 37.

22 Cooper Machinery Services advertises that they offer engine upgrades that will allow
23 engines to meet a NOx limit of 0.5 g/bhp-hr NOx for all Clark, Cooper-Bessemer, and Ingersoll

1 Rand slow speed engine models. *See* NMED Exhibit 46 – Cooper Machinery Services webpage
2 visited 07/26/2021.⁷ The modifications include a combination of adding a forced air delivery
3 system using either a turbocharger or a blower, and completing electronic system upgrades for
4 fuel, ignition, air/fuel ratio control, diagnostics, and combustion cylinder balancing. Cooper
5 Machinery lists examples of 41 units in nine states that have already been retrofitted to meet 0.5
6 g/bhp-hr NOx, and are either operating at 0.5 g/bhp-hr or are capable of operating at 0.5 g/bhp-
7 hr.

8 The California South Coast Air Quality Management District Rule 1110.2, attached as
9 NMED Exhibit 47,⁸ specifies a NOx emission limit, effective July 1, 2011, applicable to all
10 existing stationary spark and compression ignition engines (i.e., making no distinction by engine
11 type) with a nameplate rating of 50 hp or greater of 11 parts per million by volume, dry basis
12 (ppmvd) NOx at 15% O₂. This is equal to approximately 0.15 g/bhp-hr, assuming a conversion
13 factor of 1 g/bhp-hr for a lean burn engine controlled by low emission combustion technology.

14 EPA's *Stationary Reciprocating Internal Combustion Engines Updated Information on*
15 *NOx Emissions and Control Techniques*, Publication No. EPA-457/R-00-001 (September 2000),
16 summarized the results of 476 individual tests conducted from 1991 to 1998 of lean-burn engines
17 fitted or retrofitted with low emission combustion technology either by the original equipment
18 manufacturer ("OEM") or a third-party vendor. In these tests, NOx emissions ranged from 0.1
19 g/bhp-hr to 4.8 g/bhp-hr. Ninety-seven percent (97%) of these tests (460) measured emissions
20 less than or equal to 2 g/bhp-hr. Almost 75 percent (356) of the tests measured emissions less

⁷ Available at: <https://www.cooperservices.com/engines-and-compressors/upgrades/0-5-gbhp-hr-nox-solution%E2%80%8B/>

⁸ <http://www.aqmd.gov/docs/default-source/rule-book/reg-xi/rule-1110-2.pdf>

1 than or equal to 1 g/bhp-hr, and 25 percent (120) measured emissions of less than or equal to 0.5
2 g/bhp-hr. *See* NMED Exhibit 48 at p. 2-2.

3 The same EPA report summarized test results for lean burn engines controlled by SCR.
4 Summary data obtained for 1997 emission tests were of three 3,130-bhp, 4-stroke, lean-burn SI
5 engines equipped with SCR control systems and subject to a permit emission limit for NOx of 15
6 ppmv (on a dry basis corrected to 15 percent oxygen), corresponding to about 0.2 g/bhp-hr.
7 During 20 individual test runs in 1997 on these three engines, NOx emissions ranged between
8 0.11 g/bhp-hr and 0.21 g/bhp-hr. *See id.* at p. 4-15.

9 The proposed limits for CO (47 ppmvd at 15 percent O₂ or 93% reduction) and non-
10 methane non-ethane hydrocarbon (“NMNEHC”) (0.70 g/bhp-hr, as propane) for existing lean
11 burn engines greater than 1,000 bhp are based on the addition of an oxidation catalyst control.
12 This CO limit is also the same as the operating limit specified in the federal regulations at 40
13 CFR 63, Subpart ZZZZ, for non-emergency and non-remote existing 4SLB engines greater than
14 500 hp using an oxidation catalyst.⁹

15 The proposed CO limit (47 ppmvd at 15 percent O₂ or 93% reduction) is the same limit
16 as that set forth in Pennsylvania GP-5 for natural gas-fired spark ignition engines greater than
17 500 hp authorized to operate on or after February 2, 2013. This is also the same limit specified in
18 40 CFR Part 63, Subpart ZZZZ, for existing natural gas fired spark ignition non-emergency lean
19 burn engines rated greater than 500 bhp, located at an area source of hazardous air pollutants
20 (“HAP”). *See* NMED Exhibit 49. A less stringent CO standard (2.0 g/bhp-hr) in Pennsylvania
21 GP-5 applies to all spark ignition engines authorized to operate between March 10, 1997 and
22 February 2, 2013. A more stringent standard (0.30 g/bhp-hr) in GP-5 applies to engines greater

⁹ See 40 CFR part 63, subpart ZZZZ, See Table 2c, row #10; Table 2d, row #9; Table 5, #13; Table 6, Row #14.

1 than or equal to 2,370 hp authorized to operate on or after August 8, 2018. The proposed CO
2 limit of 47 ppmvd at 15 percent O₂ is approximately equal to 0.50 g/bhp-hr, assuming a
3 conversion factor of 95 ppmvd per 1.0 g/bhp-hr. *See* NMED Exhibit 37, at p. 12-13.

4 The proposed limit for NMNEHC is the same as the VOC limit in Table 1 to 40 CFR 60,
5 Subpart JJJJ, for engines greater than 500 hp and manufactured after July 1, 2010. *See* NMED
6 Exhibit 50.

7 *Existing Rich Burn Engines greater than 1,000 bhp*

8 The proposed limits for NO_x (0.50 g/bhp-hr), CO (0.70 g/bhp-hr), and NMNEHC (0.70
9 g/bhp-hr as propane) for existing rich burn engines greater than 1,000 bhp are all based on the
10 addition of NSCR controls.

11 The proposed NO_x limit is less stringent than the limits in the PA GP-5 and GP-5A (0.20
12 g/bhp-hr) for rich burn engines authorized to operate on or after February 2, 2013. The proposed
13 NO_x limit is more stringent than the New Source Performance Standard (NSPS) limit in 40 CFR
14 60, Subpart JJJJ, for engines with a manufacture date after July 1, 2007 (2.0 g/bhp-hr) and after
15 July 1, 2010 (1.0 g/bhp-hr), although the NSPS applies the same NO_x limit to both lean burn and
16 rich burn engines.

17 The proposed NO_x limit is more stringent than the numerical NO_x limits specified in
18 Colorado Reg. 7, Part E:

- 19 • Section I.D.3.b: “State only” requirements for new, modified or relocated engines
20 ≥ 500 Hp:
 - 21 ○ Constructed or relocated on or after January 1, 2007: 2.0 g/hp-hr; and
 - 22 ○ Constructed or relocated on or after January 1, 2010: 1.0 g/hp-hr).

- Section I.D.5.b: “State only” requirements for new, modified or relocated engines
≥ 1,000 Hp:
 - In service on or before November 14, 2020: 0.8 g/hp-hr.
 - Placed in service, modified, or relocated after November 14, 2020: 0.5 g/hp-hr.

All new and existing rich burn engines located in the Colorado 8-hour ozone control area are required to use NSCR. *See* Colorado Reg. 7, Part E, Sections I.A and I.B (NMED Exhibit 39).

The proposed CO limit is less stringent than the limits in Pennsylvania GP-5 and GP-5A (0.30 g/bhp-hr) for rich burn engines authorized to operate on or after February 2, 2013. The proposed CO limit is more stringent than the NSPS limit in 40 CFR 60, Subpart JJJJ, for engines with a manufacture date after July 1, 2007 (4.0 g/bhp-hr) and after July 1, 2010 (2.0 g/bhp-hr), although the NSPS applies the same NO_x limit to both lean burn and rich burn engines. The proposed CO limit is also more stringent than the limits specified in Colorado Reg. 7 for engines constructed or relocated after July 1, 2007 (4.0 g/bhp-hr) and after July 1, 2020 (2.0 g/bhp-hr) (Part E, Section I.D.3.b) and before and after November 14, 2020 (2.0 g/bhp-hr) (Part E, Section I.D.5.b).

The proposed NMNEHC limit is less stringent than the limits in Pennsylvania GP-5 and GP-5A (0.20 g/bhp-hr, excluding formaldehyde) for rich burn engines authorized to operate on or after February 2, 2013. The proposed NMNEHC limit is more stringent than the limit in NSPS Subpart JJJJ for engines with a manufacture date after July 1, 2007 (1.0 g/bhp-hr), and is the same as the limit for engines with a manufacture data after July 1, 2010 (0.7 g/bhp-hr). The proposed NMNEHC limit is more stringent than the VOC limits specified in Colorado Reg. 7

1 for engines constructed or relocated after July 1, 2007 (1.0 g/bhp-hr), and is the same (0.7 g/bhp-
2 hr) for engines constructed or relocated after July 1, 2010 (Part E, Section I.D.3.b) and for
3 engines constructed or relocated after November 14, 2020 (Part E, Section I.D.5.b).

4 The Ohio EPA provides on-line emission test summaries for many emission tests for the
5 years 2003 to 2016.¹⁰ These include many emission tests of reciprocating internal combustion
6 engines and turbines. These Ohio EPA test data show that the proposed emission limits for
7 existing lean burn and rich burn engines are readily achievable. The Ohio data for NOx, CO, and
8 VOC (as surrogate for NMNEHC) emissions from engines and turbines are presented in the
9 Engines and Turbines OH Stack Tests Spreadsheet at NMED Exhibit 51.

10 *New Spark Ignition Engines*

11 The proposed NOx emission limits for new lean burn and rich burn engines are the same
12 as those in Pennsylvania GP-5 and GP-5A for engines authorized to operate on or after August 8,
13 2018. These limits are based on vendor guarantees and other information collected by the
14 Pennsylvania Department of Environmental Protection (“PA DEP”) and summarized in the June
15 2018 Technical Support Document for Pennsylvania GP-5 and GP-5A (“PA TSD 2018”),
16 attached as NMED Exhibit 52. The NOx limits for lean burn engines are based on low emission
17 combustion designs for engines greater than 500 bhp but less than 1,000 bhp, and based on low
18 emission combustion designs or the use of add-on SCR for engines equal to or greater than 1,000
19 bhp.

20 The CO and NMNEHC limits for lean burn engines greater than 500 bhp are the same
21 limits as for existing lean and rich burn engines greater than 1,000 bhp and are based on the use
22 of add-on oxidation catalysts.

¹⁰ See <https://www.epa.ohio.gov/dapc/engineer/stackg#123883452-test-summaries>.

1 The NO_x, CO, and NMEHC limits for rich burn engines greater than 500 bhp are based
2 on the use of add-on NSCR.

3 The Ohio EPA's on-line emission test summaries include many emission tests of
4 reciprocating internal combustion engines and turbines. The Ohio test data show that the
5 proposed emission limits for new lean burn and rich burn engines are readily achievable. The
6 data for NO_x, CO and VOC (as surrogate for NMNEHC) are presented in the Engines and
7 Turbines OH Stack Tests Spreadsheet at NMED Exhibit 51.

8 *New Compression Ignition Engines*

9 The proposed NO_x emission limit for new compression ignition engines equal to or
10 greater than 500 hp of 9 g/bhp-hr is the same limit as Colorado Reg. 7 Part E, Section II.A.4.e.
11 The emission limit is based on the use of add-on SCR controls.

12 The proposed rule does not include proposed emission limits for existing compression
13 ignition engines.

14 *Stationary Combustion Turbines*

15 The proposed requirements for both existing and new turbines apply to turbines with
16 rated bhp greater than or equal to 1,000 bhp.

17 The proposed emission limits and applicability thresholds for turbines are based on the
18 PA TSD 2018 (NMED Exhibit 52), except that the proposed NO_x limits for existing turbines are
19 based on EPA Office of Air and Radiation's *Alternative Control Techniques Document – Nox*
20 *Emissions from Stationary Gas Turbines*, EPA-453/R-93-007 (January 1993) ("EPA 1993
21 ACT"), included as NMED Exhibit 53.

22 The proposed NO_x emission limits of 50 ppmvd at 15% O₂ for existing turbines, as set
23 forth in Table 3 of Section 20.2.50.113, are based on the use of water or steam injection control

1 technology. The EPA 1993 ACT for NO_x emissions from stationary combustion turbines
2 reported that water or steam injection can commonly achieve 70 to 90 percent NO_x emission
3 reductions and vendor guaranteed controlled emission rates of 25 to 75 ppmvd, with many
4 vendors offering a guarantee of 42 ppmvd. *See id.*, at Table 5-5. The Ozone Transport
5 Commission recommended the following NO_x limits for existing natural gas pipeline
6 compressor prime mover turbines:

- 7 • Turbines less than 2,000 hp – 150 ppmvd at 15% O₂
- 8 • Turbines equal to or greater 2,000 hp and less than 5,000 hp – 50 ppmvd at 15% O₂
- 9 • Turbines equal to or greater than 5,000 hp – 25 ppmvd at 15% O₂

10 *See* NMED Exhibit 54 – OTC Stationary and Area Sources Committee, *OTC Regulatory and*
11 *Technical Guideline for Control of Nitrogen Oxides (NO_x) Emissions from Natural Gas Pipeline*
12 *Compressor Fuel-Fired Prime Movers* (May 14, 2019), at p. 8-9.

13 The proposed CO and NMNEHC emission limits in Table 3 of Section 20.2.50.113 for
14 existing turbines are based on the same limits in Pennsylvania GP-5 for turbines authorized to
15 operate on or after February 1, 2013, but prior to August 8, 2018. For turbines between 1,000 and
16 15,000 HP, Pennsylvania GP-5 establishes a CO limit of 50 ppmvd at 15% O₂ and a NMNEHC
17 limit of 9 ppm NMNEHC at 15% O₂. These limits were identified as achievable for turbines
18 using good combustion practices and without the use of oxidation catalysts. These limits are
19 based on vendor data for uncontrolled turbines, and the vendor data showed that oxidation
20 catalysts were not cost effective for turbines in this size range to achieve a lower emission level,
21 according to the 2018 TSD for GP-5/GP-5A. *See* NMED Exhibit 52, at p. 75.

22 For turbines greater than or equal to 15,000 HP and authorized to operate under GP-5 on
23 or after February 1, 2013, but prior to August 8, 2018, PA DEP determined that oxidation

1 catalysts were cost effective to achieve a CO limit of 50 ppmvd at 15% O₂ (or a 93% reduction)
2 and a NMNEHC emission limit of 5 ppm NMNEHC at 15% O₂ (or a 50% reduction). *See id.*

3 The proposed NO_x, CO, and NMNEHC limits for new turbines in Table 3 of Section
4 20.2.50.113 are almost identical those in the Pennsylvania GP-5 for turbines authorized to
5 operate on or after August 8, 2018. According to the PA DEP's 2018 TSD for GP-5/GP-5A,
6 vendor data for turbines greater than or equal to 1,000 bhp but less than 5,000 bhp indicated
7 uncontrolled emission rates of 25 ppm NO_x, 25 ppm CO, and 25 ppm THC as methane, with the
8 THC emission rate converted to NMNEHC as propane, establishing an emission rate of 9 ppm
9 NMNEHC as propane. The standards in GP-5 for these new turbines are based on good
10 combustion engineering and turbine design, and not on the use of add-on controls for turbines
11 greater than 1,000 hp and less than 5,000 hp. *See id.*

12 According to the PA DEP's 2018 TSD for GP-5/GP-5A, vendor data for turbines greater
13 than or equal to 5,000 bhp but less than 15,900 bhp indicated uncontrolled emission rates of 25
14 ppm NO_x, 25 ppm CO, and 25 ppm THC as methane, with the THC emission rate converted to
15 NMNEHC as propane, establishing an emission rate of 9 ppm NMNEHC as propane. However,
16 based on stack test results, the limit for NO_x was established at 15 ppm, for CO at 10 ppm, and
17 for NMNEHC at 5 ppm as achievable without control. The PA DEP determined that oxidation
18 catalyst was not cost effective for turbines in the 5,000 to 15,900 bhp range. *See id.* The
19 Department has proposed a NMNEHC limit for new turbines greater than 1,000 bhp and less
20 than 15,900 bhp of 9 ppmvd, instead of 5 ppmvd, as indicated in Table 3 of Section 20.2.50.113
21 NMAC.

22 According to the PA 2018 TSD, vendor data for new turbines greater than or equal to
23 15,900 bhp indicated uncontrolled emission rates of 25 ppm NO_x, 25 ppm CO, and 25 ppm THC

1 as methane (9 ppm NMNEHC as propane). The PA DEP determined limits of 15 ppm for NOx,
2 10 ppm for CO, and 5 ppm for NMNEHC were achievable without controls based on stack test
3 data, and also determined that that oxidation catalysts were cost effective for turbines greater
4 than or equal to 15,900 bhp for CO and NMNEHC. Pennsylvania GP-5 includes CO limits of
5 10.0 ppmvd for turbines without controls and 1.75 (rounded to 1.8) ppmvd for turbines with
6 controls, and a single limit for NMNEHC of 5.0 ppmvd (whether controlled or uncontrolled). *See*
7 *id.*, at p. 77.

8 According to the PA 2018 TSD, recent permits and plan approvals showed that turbines
9 greater than or equal to 15,900 bhp could achieve 9.0 ppmvd NOx without controls. The PA
10 2018 TSD also noted that SCR vendors typically guaranteed 90% reductions, and that stack tests
11 for turbines in Pennsylvania controlled by SCR have achieved NOx emissions ranging from 1.6
12 to 1.8 ppmvd. As a result, PA DEP included NOx limits for turbines greater than or equal to
13 15,900 bhp of 9.0 ppmvd if uncontrolled and 2.0 ppmvd if controlled. *See id.*, at p. 72. The
14 proposed NOx limits for new turbines equal to greater than 15,900 bhp in Table 3 of Section
15 20.2.50.113 are the same as those in the Pennsylvania GP-5; i.e., 9.0 ppmvd if uncontrolled and
16 2.0 ppmvd if controlled.

17 Emission Reductions

18 *NOx Reductions – Engines*

19 Data from the NMED Equipment Report indicates there are 4,718 active internal
20 combustion engines with records for NO₂ located in Chaves, Eddy, Lea, Rio Arriba, San Juan,
21 Sandoval, and Valencia Counties (collectively, the “Subject Counties”), or designated as
22 ‘Portable.’ These 4,718 engines are situated at 1,463 unique locations.¹¹ Of these, 1,950 engines

¹¹ Engines located at refineries were removed from the analysis.

have a horsepower rating greater than 1,000 bhp. 1,866 engines lacked add-on NOx controls and may require additional NOx control (either add-on controls or low emission combustion retrofits) to meet the proposed standards. ERG estimated reductions in NOx for the various engine types as shown in the following Table.

Percent Reduction By Engine Type			
NG	Controlled by SCR / NSCR		0%
NG	Uncontrolled	Lean Burn 4-stroke >1000	49%
NG	Uncontrolled	Lean Burn 2-stroke >1000	78%
NG	Uncontrolled	Rich Burn >1000	81%
NG	NSPS JJJJ Before 2011	Lean Burn 4-stroke >1000	49%
NG	NSPS JJJJ Before 2011	Lean Burn 2-stroke >1000	75%
NG	NSPS JJJJ Before 2011	Rich Burn >1000	75%
NG	NSPS JJJJ 2011 +	Lean Burn 4-stroke >1000	49%
NG	NSPS JJJJ 2011 +	Lean Burn 2-stroke >1000	50%
NG	NSPS JJJJ 2011 +	Rich Burn >1000	50%
Diesel	Controlled	>1000 hp	55%

In cases where the engine type was unknown, ERG assumed the engine was lean burn 4-stroke because that is the most common engine type for those over 1,000 hp.

The percent reductions by engine type were estimated as either (1) the difference between uncontrolled emission factors from the U.S. EPA's AP-42 Compilation of Air Emissions Factors for gas and diesel industrial engines (NMED Exhibit 55) and the proposed limits in 20.2.50.113 NMAC for engines not subject to NSPS; or (2) the difference between the NSPS emission limits in 40 CFR 60, Subpart JJJJ ("NSPS Subpart JJJJ"), and the proposed emission limits in 20.2.50.113 NMAC for engines currently subject to NSPS Subpart JJJJ because some of the proposed emission limits in 20.2.50.113 NMAC are more stringent than those in NSPS Subpart JJJJ.

ERG estimated total baseline allowable NOx emissions from all 4,718 operating internal combustion engines located in the Subject Counties, or designated as "Portable." Allowable NOx

1 emissions from those units were 62,005 tpy. ERG then estimated the NOx emission reductions
2 from implementing the proposed regulations on existing engines. For the 1,866 uncontrolled
3 engines and partially controlled engines that are subject to NSPS Subpart JJJJ, ERG estimated
4 reductions of NOx based on the NOx control technologies discussed above by applying the
5 ‘Percent Reduction By Engine Type’ shown in the table above.

6 Adding controls to uncontrolled engines would reduce NOx emissions by 17,905 tpy,
7 leading to a 28.9% overall reduction in NOx emissions from operating engines from the baseline
8 emissions. See NMED Exhibit 56 - ICE Reductions and Costs NO₂ Spreadsheet.

9 *VOC Reductions - Engines*

10 Data from the NMED Equipment Report indicates there are 4,276 active internal
11 combustion engines with records for allowable VOC emissions located in the Subject Counties,
12 or designated as “Portable”. These 4,276 engines are situated at 1,339 unique locations.¹² Of
13 these, 2,041 engines have a horsepower rating great than 1,000 bhp. Engines with VOC controls
14 (catalytic oxidation, catalytic converter, flare, NSCR); engines subject to NSPS (40 CFR 60,
15 Subpart IIII or Subpart JJJJ); and engines subject to National Emission Standards for Hazardous
16 Air Pollutants (“NESHAP”) (40 CFR 63, Subpart ZZZZ) were considered to have adequate VOC
17 controls to meet the proposed standards. For the remaining 186 uncontrolled engines, ERG
18 calculated VOC emission reductions using the following considerations: (1) if the engine was
19 uncontrolled and not subject to an NSPS or NESHAP for engines, a 90% VOC emission
20 reduction for lean-burn spark ignition engines was calculated based on adding catalytic
21 oxidation; and (2) if the engine was uncontrolled and not subject to an NSPS or NESHAP for
22 engines, a 90% VOC emission reduction for rich-burn spark ignition engines and compression

¹² Engines located at refineries were removed from the analysis.

1 ignition engines was calculated based on adding SNCR. In cases where the engine type was
2 unknown, ERG assumed the engine was lean burn 4-stroke because that is the most common
3 engine type for those over 1,000 hp.

4 ERG estimated emissions from the entire inventory of 4,276 operating internal
5 combustion engines located in the Subject Counties or designated as “Portable” at 24,224 tpy of
6 VOC. ERG then estimated the VOC emission reductions that would be achieved by
7 implementing the proposed requirements for existing engines. For the 186 uncontrolled engines,
8 ERG estimated reductions of 1,663 tpy of VOC based on the use of an add-on control to achieve
9 the required emission reduction to meet the proposed standard, leading to a 6.8% overall
10 reduction in VOC emissions from existing engines. See NMED Exhibit 57 – ICE Reductions and
11 Costs VOC Spreadsheet.

12 Emission reductions were estimated for VOC instead of NMNEHC because the allowable
13 emissions data are for VOC, the limits for NMNEHC are a surrogate for VOC, and the two are
14 nearly equal.

15 Emission reductions were not estimated for CO. The limits for CO are intended to ensure
16 good combustion practices that will lead to further VOC reductions.

17 *NOx Reductions - Turbines*

18 Data from the NMED Equipment Report indicates there are 160 active combustion
19 turbines in the O&G industry with records for NOx located in the Subject Counties. These 160
20 turbines are situated at 44 unique locations. Of these, 136 turbines have a horsepower rating
21 equal to or greater than 1,000 bhp. ERG filtered out turbines that are regulated by NSPS (40 CFR
22 60, Subpart GG Subpart KKKK) from the analysis, as these federal rules already limit NOx

1 emissions. The remaining 51 combustion turbines were then evaluated for appropriate NOx
2 reduction measures.

3 For turbines with a horsepower rating less than 15,900, ERG applied water or steam
4 injection as NOx control. This is based on Tables 6-1 and 6-6 of the EPA 1993 ACT. *See*
5 NMED Exhibit 53 at pp. 6-3 and 6-15. Using water or steam injection on an uncontrolled
6 combustion turbine results in 71% control of NOx. For turbines with a horsepower rating greater
7 than 15,900, ERG applied SCR as NOx control. This is based on the PA TSD 2018. Using SCR
8 on an uncontrolled combustion turbine results in 90% control of NOx.

9 ERG calculated the allowable NOx emissions from the entire inventory of 160 active
10 combustion turbines located in the Subject Counties. Emissions from these units total 10,313 tpy
11 of allowable NOx. ERG then examined the effect of implementing the proposed regulations on
12 the 51 unregulated and uncontrolled combustion turbines with a horsepower rating greater than
13 1,000. Applying controls to these units results in a reduction of 3,377 tpy of allowable NOx. The
14 reductions are based on the percent reductions by engine horsepower rating as indicated above.
15 Adding controls to uncontrolled combustion turbines with horsepower ratings greater than 1,000
16 would result in a 32.7% overall reduction in NOx emissions. See NMED Exhibit 58 – Turbines
17 Reductions and Costs NO₂ Spreadsheet.

18 *VOC Reductions - Turbines*

19 Data from the NMED Equipment Report indicates there are 144 active combustion
20 turbines in the O&G industry with records for allowable VOC emissions located in the Subject
21 Counties. These 144 turbines are situated at 39 unique locations. The estimated baseline
22 allowable VOC emissions from the current inventory of 144 active combustion turbines located
23 in the Subject Counties is 707 tpy of VOC.

1 Of these, 122 turbines have a horsepower rating equal to or greater than 1,000 bhp. ERG
2 filtered out turbines that: (1) have VOC controls (catalytic oxidation); or (2) are regulated by
3 NESHAP 40 CFR 63, Subpart YYYY (“NESHAP Subpart YYYY”). ERG filtered out turbines
4 that are subject to NESHAP Subpart YYYY because turbines complying with this NESHAP
5 would likely be using oxidation catalysts, so no additional reductions would be achieved.

6 Of the remaining 115 uncontrolled and unregulated combustion turbines, ERG
7 determined that, for 76 combustion turbines, the allowable VOC emissions in the permit data
8 provided by NMED was lower than the NMNEHC tpy emissions allowed under the proposed
9 NMNEHC limits. The PA DEP 2018 TSD included emission factors (lb NMNEHC/MMBtu heat
10 input) and equations to calculate MMBtu/hr from horsepower. *See* NMED Exhibit 52 at p. 75.
11 These were used to calculate the allowed NMNEHC in tpy under the NMED proposed
12 NMNEHC emission limits (9 ppm and 5 ppm). For these 76 turbines, it was assumed that no
13 additional controls or reductions would be needed to meet the proposed standard, so no costs or
14 reductions were assigned.

15 ERG estimated the emission reductions from 39 turbines without controls as the
16 difference between the allowable VOC emissions in the permit data and the estimated NMNEHC
17 emissions under the proposed emission limits. The emission reductions are based on the use of
18 an add-on control (oxidation catalyst) to achieve the VOC (NMNEHC) emission limits in the
19 proposed NM standards.

20 Adding controls to these 39 combustion turbines would reduce VOC emissions by 353
21 tpy, leading to a 49.9% overall reduction in VOC emissions from combustion turbines. *See*
22 NMED Exhibit 59 – Turbines Reductions and Costs VOC Spreadsheet.

1 Emission reductions were estimated for VOC instead of NMNEHC because the allowable
2 emissions data are for VOC, the limits for NMNEHC are a surrogate for VOC, and the two are
3 nearly equal.

4 Emission reductions were not estimated for CO. The limits for CO are intended to ensure
5 good combustion practices that will lead to further VOC reductions.

6 Costs of Reductions

7 *Costs of NOx Reductions - Engines*

8 The annualized costs of NOx emission reductions for the 1,866 uncontrolled and partially
9 controlled natural gas-fired spark-ignition engines were estimated by applying cost equations for
10 the different types and sizes of engines. In cases where the engine type was unknown, ERG
11 assumed the engine was a lean burn 4-stroke because that is the most common engine type for
12 those over 1,000 hp.

13 For 2-stroke and 4-stroke lean-burn engines, costs were calculated for adding Low
14 Emission Combustion (“LEC”) Technology as a retrofit. As described previous, LEC consists of
15 retrofits that allow engines to operate on extremely lean fuel mixtures to minimize NOx
16 emissions. The LEC retrofit may include: (1) redesign of cylinder head and pistons to improve
17 mixing (on smaller engines), (2) Precombustion chamber (on larger engines), (3) Turbocharger,
18 (4) High energy ignition system, (5) Aftercooler, and (6) Air-to-fuel ratio controller. Cost
19 information for LEC retrofits for lean burn engines rated less than 3,000 bhp comes from a NOx
20 emission control assessment prepared for the EPA Cross State Air Pollution Rule for the 2008
21 Ozone NAAQS. *See NMED Exhibit 60 – EPA Office of Air and Radiation, Final Technical*
22 *Support Document (TSD) for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS –*
23 *Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance*

1 *Final TSD*, Docket ID No. EPA-HQ-OAR-2015-0500 (August 2016), at Appendix A, p. 5-5.
2 Cost information for LEC retrofits for lean burn engines rated equal to or greater than 3,000 bhp
3 comes from a document prepared for the Interstate Natural Gas Association of America
4 (“INGAA”) titled “Availability and Limitations of NOx Emission Control Resources for Natural
5 Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission
6 Industry.” See NMED Exhibit 61 – INGAA Foundation Final Report No. 2014.03, at p. 25-29.

7 Cost information for adding NSCR to control NOx from rich-burn engines comes from a
8 2006 memo prepared for the U.S. EPA to support development of the NSPS and NESHAP for
9 stationary spark ignition engines. NMED Exhibit 62 – Alpha-Gamma Technologies, Inc.,
10 *Control Costs for Reciprocating Internal Combustion Engines at Major and Area Sources*, EPA
11 Docket Item No. EPA-HQ-OAR-2005-0030-0005 (April 28, 2006). Cost information for adding
12 NSCR to control NOx from rich-burn engines also comes from a 2010 memo prepared for EPA
13 to support amendments to the NSPS and NESHAP for stationary spark ignition engines. NMED
14 Exhibit 63 – EC/R, Inc., *Control Costs for Existing Stationary RICE*, EPA Docket Item No.
15 EPA-HQ-OAR-2008-0708-0554 (June 29, 2010) (“2010 RICE Memo”). Because the two memos
16 presented different cost equations for controlling NOx from rich burn engines using NSCR, ERG
17 compared the NSCR costs using the two equations for different size engines. The equation in the
18 2010 RICE Memo estimated higher capital costs but lower annual costs for NSCR for rich burn
19 engines greater than 1,000 bhp, so the more recent 2010 annual cost equation was used for the
20 cost analysis for rich-burn engines.

21 Costs were scaled from 2005 dollars (2005\$) to 2019 dollars (2019\$) for SCR, and from
22 2001\$ (for engines less than 3,000 hp) or 2013\$ (for engines equal to or greater than 3,000 hp)

1 for LEC using the Chemical Engineering Plant Cost Index (“CEPCI”), which is an index used to
2 adjust cost estimates from one year to a different year.¹³

3 Full details on how these cost equations were applied is set forth in NMED Exhibit 56 –
4 ICE Reductions and Costs NO₂ Spreadsheet.

5 Because the proposed NO_x emission limit for compression ignition engines applies only
6 to new engines, no costs were estimated for existing compression ignition engines.

7 The total annualized costs of adding LEC to lean-burn spark ignition engines and NSCR
8 to rich-burn spark ignition engines was estimated to be \$120,267,152 per year, at an average
9 annual cost per engine of \$64,452 and a cost per ton of NO_x reduced of \$6,717.

10 *Costs of VOC Reductions - Engines*

11 ERG estimated the cost of adding VOC controls to those engines that are not already
12 controlled with either SNCR for rich burn engines or oxidation catalyst for lean burn engines.
13 ERG assumed that engines subject to NSPS Subpart ZZZZ would already have VOC controls in
14 order to comply with the limits required under those regulations.

15 The costs of adding NSCR for VOC control for rich burn engines were already accounted
16 for in the NO_x cost estimates (NSCR controls NO_x, CO, and VOC emissions), and no further
17 control costs were added for rich burn engines. Therefore, these cost control estimates only
18 include the cost of adding catalytic oxidizers to control VOC emissions from uncontrolled lean
19 burn engines that lack oxidation catalysts and that are not subject to NSPS Subpart ZZZZ.

¹³ The CEPCI is published monthly and annually by *Chemical Engineering* and is described on the magazine’s website (<https://www.chemengonline.com/pci-home>) as follows: “The CEPCI consists of a composite index assembled from a set of four sub-indexes: Equipment; Construction Labor; Buildings; and Engineering & Supervision. Each index and subindex is the weighted sum of several components. Most of these components correspond to Producer Price Indexes (PPIs), updated and published monthly by the U.S. Department of Labor’s Bureau of Labor Statistics.”

1 In cases where the engine type was unknown, ERG assumed the engine was lean burn 4-
2 stroke because that is the most common engine type for those over 1,000 hp.

3 Costs information for adding oxidation catalysts to control VOC emissions from 2-stroke
4 lean-burn engines and 4-stroke lean-burn engines comes from equations from the 2010 RICE
5 Memo. *See* NMED Exhibit 63 at Section 4.0.

6 Costs were scaled from 2009\$ to 2019\$ using the CEPCI.

7 Full details on how ERG applied these cost equations is set forth in the ICE Reductions
8 and Costs VOC Spreadsheet at NMED Exhibit 57.

9 The annualized costs of VOC emission reductions for natural gas-fired spark-ignition
10 engines were calculated by applying the control costs for adding oxidation catalysts to 172
11 uncontrolled lean burn engines. Total annualized costs for these 172 engines would be
12 approximately \$1,626,842 per year at an average annual cost per engine of \$9,458 and a cost per
13 ton of VOC reduced of \$990.

14 *Costs of NOx Reductions - Turbines*

15 The annualized costs of NOx emission reductions were estimated for the 51 uncontrolled
16 natural gas-fired combustion turbines. The cost for NOx emission reductions for the 48
17 uncontrolled turbines with horsepower rating less than 15,900 were estimated by applying cost
18 estimates for steam injection from Tables 6-1 and 6-6 of the EPA 1993 ACT. *See* NMED Exhibit
19 53, at pp. 6-3 and 6-15. The cost for NOx emission reductions for the 3 uncontrolled turbines
20 with horsepower rating greater than 15,900 were estimated by applying cost equations for adding
21 SCR from Table 19 of the PA TSD 2018. Costs were scaled from 2016\$ to 2019\$ using the
22 CEPCI.

Full details on how ERG applied these cost equations is available in the Turbine Reductions and Costs NO₂ Spreadsheet at NMED Exhibit 58.

The total annualized costs of NO_x emission reductions for these 51 natural gas-fired turbines is approximately \$13,764,391 per year at an average annual cost per turbine of \$269,890 and a cost per ton of NO_x reduced of \$4,076.

Costs of VOC Reductions - Turbines

To estimate costs of VOC reductions for turbines, ERG assumed that an oxidation catalyst is added as a control device to 39 uncontrolled turbines that are unregulated by an NSPS or NESHAP, and that have allowable VOC emissions that exceed the proposed limits.

Cost information for adding oxidation catalysts to control VOC emissions from 39 turbines are from the PA TSD 2018. Costs were scaled from 2016\$ to 2019\$ using the Chemical Engineering Plant Cost Index.

Full details on how these ERG applied theses cost equations is available in the Turbine Reductions and Costs VOC Spreadsheet at NMED Exhibit 59.

The total annualized costs of VOC emission reductions for 39 natural gas-fired turbines are estimated at \$3,392,186 per year, with an average annual cost per turbine of \$86,979 and a cost per ton of VOC reduced of \$9,608.

Section 20.2.50.114 – Compressor Seals

Applicability

Section 20.2.50.114 applies to centrifugal compressors using wet seals and reciprocating compressors located at tank batteries, gathering and boosting stations, natural gas processing plants, and natural gas compressor stations. Centrifugal compressors and reciprocating compressors located at well sites are not subject to the requirements of Section 20.2.50.114.

1 Description of Equipment and Process

2 Compressors are used throughout the oil and natural gas industry to compress gas for
3 processing, movement through pipelines, and other needs. Compressors are mechanical devices
4 that increase the pressure of natural gas and allow the natural gas to be transported in pipelines
5 from the production site, through the processing and supply chain, and to the consumer. Vented
6 emissions from compressors occur from seals (wet seal compressors) or packing surrounding the
7 mechanical compression components (reciprocating compressors) of the compressor. These
8 emissions typically increase over time as the compressor components begin to wear and degrade.

9 *Reciprocating Compressors*

10 In a reciprocating compressor, natural gas enters the suction manifold, and then flows into
11 a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the
12 crankshaft powered by a reciprocating internal combustion engine. Emissions occur when natural
13 gas leaks around the compressor piston rod when pressurized natural gas is in the cylinder. The
14 compressor piston rod packing system consists of a series of flexible rings that create a seal around
15 the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. Over
16 time, the rings become worn and the packaging system needs to be replaced to prevent excessive
17 leaking from the compression cylinder. See Figure 1 for a depiction of a typical rod compressor
18 packing system configuration.

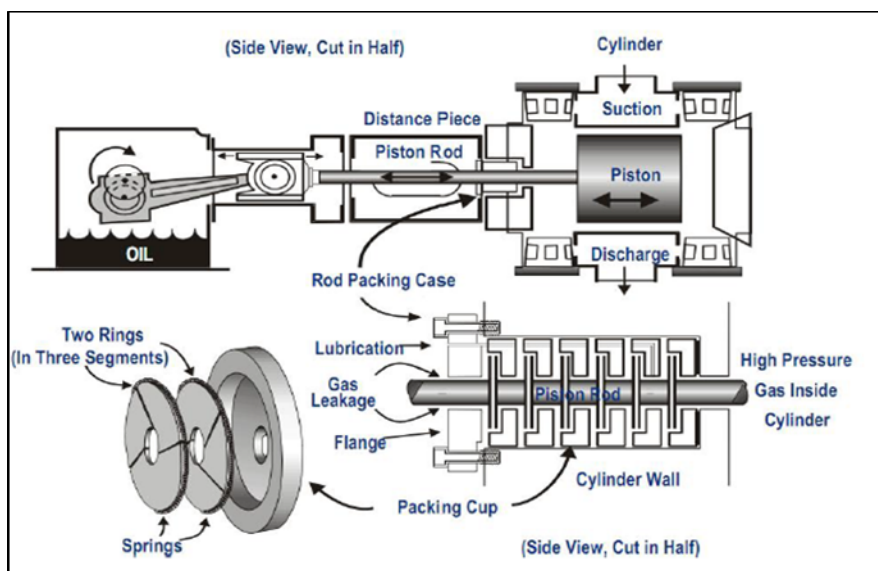


Figure 1. Typical Reciprocating Compressor Rod Packing System Diagram

Centrifugal Compressors

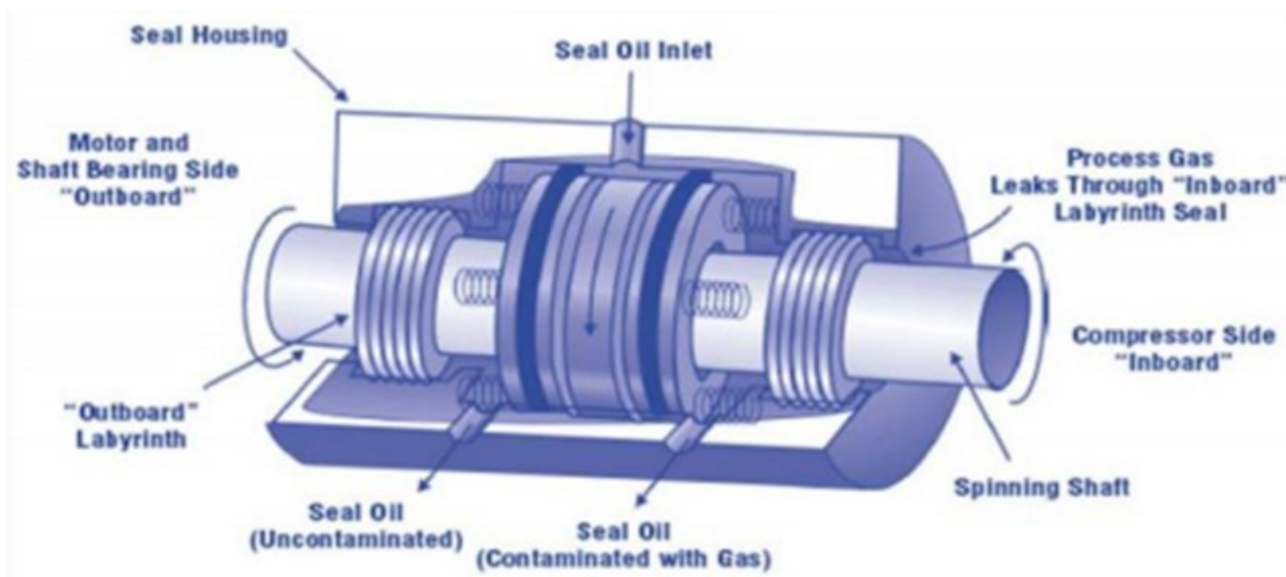
Centrifugal compressors use a rotating disk or impeller to increase the velocity of the natural gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy. These compressors are primarily used for pipeline transport of natural gas in the natural gas processing and transmission segments of the industry. These compressors require seals around the rotating shaft to prevent high pressure gases from escaping where the shaft exits the compressor casing. Many centrifugal compressors use wet (i.e., oil-filled) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. Other compressors, including most newer compressors, use a dry seal with a mechanical barrier around the rotating shaft to prevent natural gas from escaping.

Wet seals use a specialty oil that is circulated between rings around the compressor shaft under higher pressure than the gas in the adjacent compressor case, forming a barrier against compressed gas leakage. In the wet seal design shown in Figure 2, the center ring is attached to the rotating shaft, while the two rings on each side are stationary in the seal housing and pressed

1 against a thin film of oil flowing between the rings to both lubricate and act as a leak barrier. “O-
2 ring” rubber seals prevent leakage around the stationary rings. Very little gas escapes through the
3 oil barrier; however, gas is entrained in the oil that comes in direct contact with the high-pressure
4 gas at the “inboard” (compressor side) interface, thus contaminating the seal oil. Prior to
5 recirculation, the seal oil must be purged of natural gas in a process called “seal oil degassing.”
6 The gas is primarily methane, but also contains some VOC; the fraction of VOC depends on the
7 point in the production chain the compressor is located. Methane and VOC released during seal
8 oil degassing are commonly vented to the atmosphere with vent outlets usually located in
9 elevated areas that are not easily accessible to operators for inspection or maintenance (e.g., roof
10 vent stacks). As a result, the majority of methane and VOC emissions from a centrifugal
11 compressor often go undetected by operators.

12 Figure 2 displays a typical centrifugal compressor wet seal. The seal oil enters through
13 the inlet (top) and provides a barrier to gas attempting to escape by forming two thin films under
14 higher pressure between the center rotating ring and the two stationary rings (seen with
15 surrounding O-rings).

1



2

3

Figure 2. Typical Centrifugal Compressor Wet Seal

4

Control Options for Compressor Seals

5

Reciprocating Compressors

6

VOC emissions from reciprocating compressor rod packing can be minimized by

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replacing the rod packing on a regular basis before it becomes excessively worn. A typical

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regulatory schedule is to replace the rod packing seals after every 26,000 hours of operation or

9

every 36 months, whichever is later. A second control option is to collect emissions from the rod

10

packing under negative pressure and route them via a closed vent system to a control device, a

11

recovery system, a fuel cell, a process stream, or to be used as fuel. Figure 3 shows a general

12

diagram of a closed vent collection and control or recovery system.

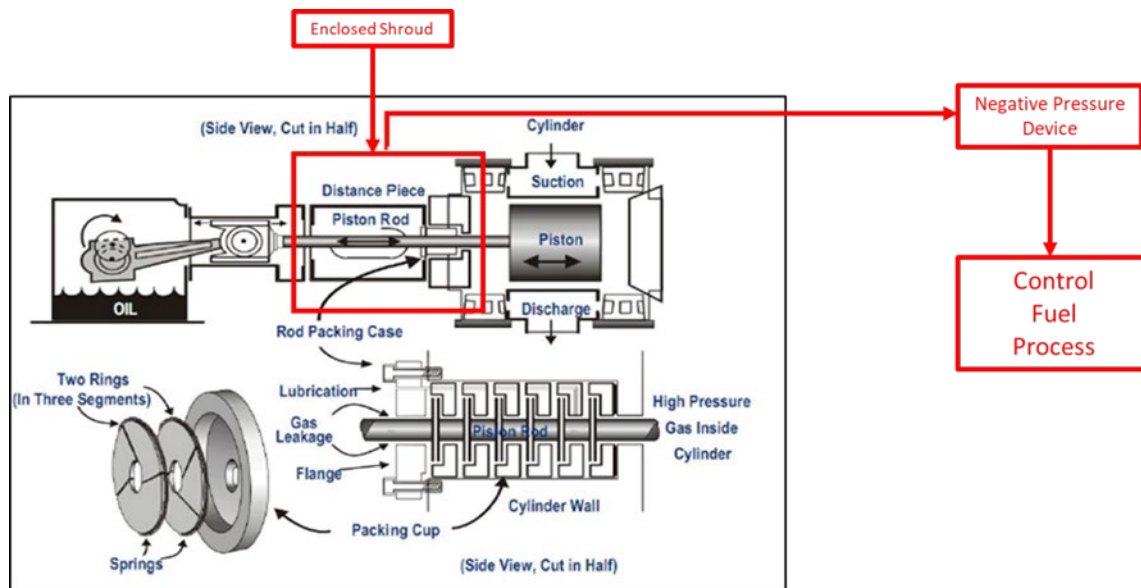


Figure 3. General Flow Process for a Closed Vent System. (Existing equipment shown in black and new equipment for closed vent system and control or recovery shown in red)

Centrifugal Compressors

Centrifugal compressor seal oil that is contaminated with entrained gas is typically routed directly to an atmospheric pressure degassing tank in which the entrained gas (methane and VOC) will evaporate from the seal oil and is then vented to the atmosphere. A wet seal fluid degassing system that is designed to capture the released methane and VOC is shown in Figure 4. In the capture system, the contaminated seal oil separated from entrained gas in a separator operating at seal oil pressure with gas flow controlled by a critical orifice. The entrained gas captured from the seal oil is routed to a seal oil demister to remove entrained seal oil before routing the gas to a control device, a process, for use as a fuel, or to the suction side of a compressor to be pressurized and put back into the pipeline or another use. The seal oil from the bottom of the high-pressure seal oil degassing separator flows to the atmospheric degassing separator where the remaining, but now reduced, volume of entrained/dissolved gas is removed and vented to the atmosphere. The regenerated seal oil is then recirculated back to the compressor seal oil system.

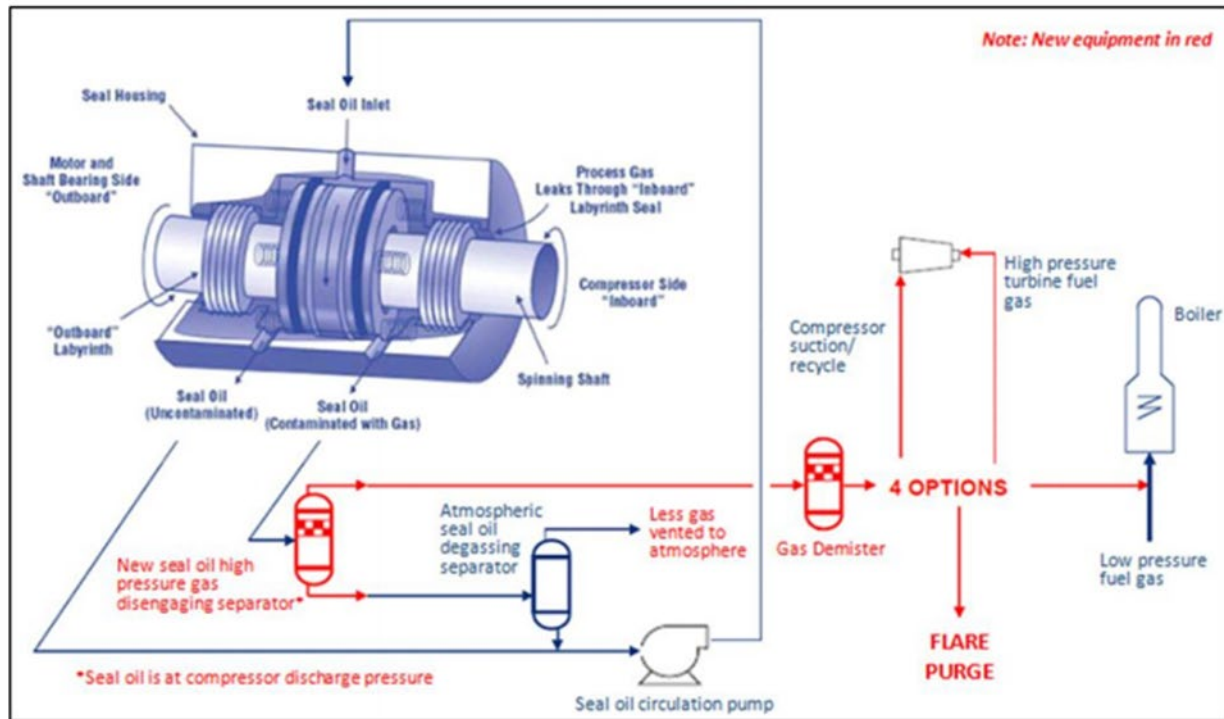


Figure 4. General process flow of wet seal degassing recovery system. (Existing equipment shown in blue and new equipment for seal oil degassing recovery shown in red)

Proposed Rule Requirements for Compressor Seals

Section 20.2.50.114 requires owners and operators of existing centrifugal compressors to control VOC emissions from centrifugal compressor wet seal fluid degassing systems by at least 95 percent within two years of the effective date of Part 50. Emissions must be captured and routed through a closed vent system to a control device, recovery system, fuel cell, or a process stream. Owners and operators of new centrifugal compressors are required to control VOC emissions from wet seal fluid degassing systems by at least 98 percent upon startup, capturing and routing emissions through a closed vent system to a control device, recovery system, fuel cell, or process stream.

Owners and operators of existing reciprocating compressors must either replace the rod packing after every 26,000 hours of compressor operation or every 36 months, whichever is

1 later, or collect VOC emissions from the rod packing under negative pressure and route them
2 through a closed vent system to a control device, recovery system, fuel cell, or a process stream.
3 Rod packing for new reciprocating compressors must be replaced after every 26,000 hours of
4 operation or every 36 months, whichever is later, or emissions must be collected from the rod
5 packing using a closed vent system to a control device, a recovery system, fuel cell or a process
6 stream.

7 All centrifugal and reciprocating compressors must be equipped with an EMT in
8 accordance with Section 20.2.50.112, and the owner or operator must comply with the general
9 monitoring, recordkeeping, and reporting requirements in that Section. An owner or operator
10 complying with the emission standards in Section 20.2.50.114 through the use of a closed vent
11 system and control device, including a wet seal fluid degassing system, must also comply with
12 the closed vent system and control device monitoring, recordkeeping, and reporting requirements
13 in Section 20.2.50.115.

14 Owners and operators complying with the emission standards for new or existing
15 reciprocating compressors are required to continuously monitor the hours of operation with a
16 non-resettable hour meter, and track the number of hours from initial startup or from the previous
17 reciprocating compressor rod packing replacement. Owners and operators of reciprocating
18 compressors who are collecting emissions under negative pressure and routing those emissions
19 through a closed vent system to a control device, a recovery system, fuel cell or a process stream
20 are required to monitor the collection system semi-annually to ensure that it continues to operate
21 under negative pressure.

22 Owners and operators of centrifugal compressors using wet seal fluid degassing systems
23 are required to maintain records of the following: location of the compressor; date of

1 construction, reconstruction, or modification of the compressor; required monitoring data; and
2 the type, make, model and identification number of the control device used to comply with the
3 emission standards.

4 Owners and operators of reciprocating compressors are required to maintain a record of
5 the following: location of the compressor; date of construction, reconstruction, or modification of
6 the compressor; and the required monitoring data.

7 Basis for Proposed Requirements

8 *Compressor Seals on Centrifugal Compressors*

9 The proposed requirement in Section 20.2.50.114.B(1) to control VOC emissions from a
10 centrifugal compressor wet seal fluid degassing system by at least 95 percent is based on NSPS
11 Subpart OOOOa at 40 CFR § 60.5380a(a)(1)-(2), which requires that owners and operators
12 reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing
13 system by 95.0 percent. The federal rule requires the wet seal degassing system to be equipped
14 with a cover and closed vent system that routes the gas to a control system or a process.

15 *Compressor Seals on Reciprocating Compressors*

16 The proposed requirement in Section 20.2.50.114.B(2)(a) to control VOC emissions from
17 a reciprocating compressor by replacing the reciprocating compressor rod packing after every
18 26,000 hours of compressor operation or every 36 months is based on NSPS Subpart OOOOa at
19 40 CFR § 60.5385a(a)(1)-(2), which requires that owners and operators replace the rod packing
20 on or before the compressor has operated for 26,000 hours or prior to 36 months from the date of
21 the most recent rod packing replacement.

22 The proposed requirement in Section 20.2.50.114.B(2)(b) to collect emissions from the
23 rod packing under negative pressure and route them via a closed vent system to a control device,

recovery system, fuel cell, or a process stream is based on NSPS Subpart OOOOa at 40 CFR § 60.5385a(a)(3), which requires that owners and operators collect emissions from the rod packing with a system under negative pressure and route to a process through a closed vent system.

Estimated Emissions Reductions

Reciprocating Compressors

The NMED Equipment Data indicates that there are 3,740 active oil and gas industry reciprocating engines located in the Subject Counties, or designated as “Portable.” Engines located at refineries, mining, onsite remediation, reinjection sites, and wellheads were removed from the analysis. Engines identified as “generators” or “pump jack” engines in the emission unit description were also removed from the analysis. Engines whose capacity was stated in units of “kW” (kilowatts) were removed from the analysis under the assumption that they were used to power generators. ERG assumed that each of the remaining reciprocating engines is powering a reciprocating compressor. These 3,740 active reciprocating compressors are located at 1,193 unique locations. Of these, 2,612 reciprocating compressors are not already regulated by NSPS Subpart OOOO or OOOOa, based on their manufacture date, construction date, or the “Sub-Program Information” in the NMED Equipment Data.

ERG estimated emissions from the compressor seals of these 2,612 reciprocating compressors using the emission factor from Tables 5-2 and 5-3 of the EPA CTG. *See* NMED Exhibit 34. For reciprocating compressors located at gathering and boosting stations, the emission factor is 3.42 tpy of VOC. For reciprocating compressors located at gas processing sites, the emission factor is 6.12 tpy of VOC. ERG used the emission factor for gathering and boosting stations for all facility types (including production facilities and compression stations) other than natural gas processing plants. The CTG does not contain a separate emission factor for

1 reciprocating compressors at natural gas compression stations. However, because larger
2 compression stations are generally located downstream from a gas processing plant, and the gas
3 therefore has a lower VOC content, ERG assumed for this analysis that the emission factor for
4 gathering and boosting would also be representative for compression stations. Total baseline
5 VOC emissions before controls for these 2,612 reciprocating compressors are estimated at 9,260
6 tpy of VOC.

7 ERG estimated annual emission reductions from the reciprocating compressor seals by
8 increasing the frequency of replacing the rod packing using the estimated emission reductions
9 (tpy VOC per compressor) from Table 5-4 of the CTG. The CTG estimated the reductions
10 achieved by increasing the replacement frequency from every 4 years to every 3 years. For
11 reciprocating compressors located at gathering and boosting stations, this estimated emission
12 reduction is 1.9 tpy VOC, and for reciprocating compressors located at processing sites the
13 estimated emission reduction is 4.89 tpy VOC. For the 2,612 reciprocating compressors in the
14 NMED data, total annual emission reductions with increased rod packing replacement were
15 estimated to be 5,325 tpy VOC, a 57.5 percent reduction, and emissions after replacement of rod
16 packing were estimated to be 3,935 tpy VOC. *See* NMED Exhibit 64 – Compressor Seals -
17 Reciprocating Engines Spreadsheet.

18 *Centrifugal Compressors*

19 The NMED Equipment Data indicates there are 160 active oil and gas industry
20 combustion turbines located in the Subject Counties. ERG removed from the analysis 25 turbines
21 located at refineries and wellheads or designated as generators. ERG assumed that each of the
22 remaining 135 turbines is powering a centrifugal compressor. These 135 centrifugal compressors
23 are situated at 36 unique locations. Of these, 116 centrifugal compressors are not already

1 regulated by NSPS Subparts OOOO or OOOOa, based on their manufacture date, construction
2 date, or “Sub-Program Information” in the NMED Equipment Data.

3 ERG assumed that each of these 116 compressors is equipped with wet seals, based on an
4 applicable EPA 2014 Natural Gas Star Program document which states that “most new
5 compressors [are] equipped with [a] dry seal.” See NMED Exhibit 65 – Partner Reported
6 Opportunities (PROs) for Reducing Methane Emissions, *Wet Seal Degassing Recovery System*
7 *for Centrifugal Compressors* (2014) (“Centrifugal Compressors Technical Document”).¹⁴ ERG
8 assumed that the remaining 19 compressors had dry seals.

9 ERG estimated baseline emissions from the compressor seals of the 116 wet seal and 19
10 dry seal centrifugal compressors using the emission factors from Tables 5-2 and 5-3 of the EPA
11 CTG. See NMED Exhibit 34. The EPA CTG includes VOC emission factors for centrifugal
12 compressors located only at natural gas processing sites, and these emission factors are 19.1 tpy
13 VOC for centrifugal compressors with wet seals and 2.4 tpy VOC for compressors with dry
14 seals. The EPA CTG did not include separate VOC emission factors for centrifugal compressors
15 located at other types of facilities (e.g., gathering and boosting stations or natural gas
16 compression stations). As a result, ERG used the same emission factors (19.1 tpy of VOC per
17 compressor with wet seals and 2.4 tpy VOC for dry seals) for estimating baseline VOC
18 emissions for all centrifugal compressors, depending on whether or not they were subject to the
19 NSPS. Total VOC emissions before controls for the 116 centrifugal compressors that predate the
20 NSPS are estimated at 2,197 tpy of VOC, and the VOC for the other 19 centrifugal compressors
21 that are likely subject to the NSPS are estimated at 46 tpy. Total baseline VOC emissions from
22 all centrifugal compressors are 2,243 tpy VOC.

¹⁴ Available at: <https://www.epa.gov/natural-gas-star-program/wet-seal-degassing-recovery-system-centrifugal-compressors>

ERG estimated emission reductions from the compressor seals on centrifugal compressors after installation of a wet seal degassing recovery and re-use system. The estimated emission reductions after installation of a wet seal degassing recovery and re-use system is from the CTG, which assumed “that routing VOC emissions from a wet seal fluid degassing system to a process reduces VOC emissions greater than or equal to a combustion device (i.e., greater than or equal to 95 percent).” A 95% reduction in VOC emissions is equivalent to 1.0 tpy VOC after control. Total emissions after installation of a wet seal degassing recovery and re-use system for these 116 centrifugal compressors are therefore estimated at 110 tpy VOC.

Requiring centrifugal compressors to install a wet seal degassing recovery and re-use system would result in a 95 percent reduction in VOC emissions for these previously unregulated sources. Overall VOC reductions would be 2,087 tpy VOC, and the overall percent VOC emission reduction would be 93%. *See* NMED Exhibit 66 – Compressor Seals - Turbines Spreadsheet.

Estimated Costs

Reciprocating Compressors

ERG estimated the annualized costs of VOC emission reductions for the 2,612 uncontrolled reciprocating compressors by applying cost estimates from Table 5-5 of the CTG. Costs were scaled from 2012\$ to 2019\$ using the CEPCI. Since rod packing replacement is done every three years, the capital costs of replacement were annualized over three years, assuming an interest rate of 7%. The resulting annual cost per compressor for rod packing replacement is \$2,237 per year for a compressor in the gathering and boosting sector, and \$1,695 per year for a compressor in the processing sector. These annual costs are incremental costs compared to the

annual costs of replacing the rod packing every four years. The total cost for replacing rod packing every three years for all 2,612 reciprocating compressors is \$5,778,289.

Full details on how these cost equations were applied can be found in the Compressor Seals – Reciprocating Engines Spreadsheet. *See* NMED Exhibit 64.

Centrifugal Compressors

ERG estimated the annualized costs of VOC emission reductions for the 116 uncontrolled centrifugal compressors located at 36 unique locations by applying the cost estimates from Exhibit 3 of the Centrifugal Compressors Technical Document. *See* NMED Exhibit 65. Costs were scaled from 2011\$ to 2019\$ using the CEPCI. Because some of the equipment for a degassing system can be shared across all compressors at a site, the capital cost of installing these systems per compressor decreases with an increasing number of compressors at a site. EPA estimated the cost for sites with one compressor and four compressors in the Centrifugal Compressors Technical Document. ERG adopted the same procedure to calculate the capital and annual costs for different numbers of compressors, as presented in the following table. The capital costs of installing the degassing system were annualized over a period of five years, assuming an interest rate of 7%.

# of Compressors at a Site	Total Capital Cost (\$2019)	Annualized Cost (\$2019)
1 Compressor	\$34,228	\$8,348
2 Compressors	\$53,935	\$13,154
3 Compressors	\$73,643	\$17,961
4 Compressors	\$93,350	\$22,767
5 Compressors	\$113,057	\$27,574
6 Compressors	\$132,764	\$32,380
7 Compressors	\$152,471	\$37,186
8 Compressors	\$172,179	\$41,993
9 Compressors	\$191,886	\$46,799
10 Compressors	\$211,593	\$51,606

1 ERG calculated the annualized cost for installing a degassing system at each of the 36
2 locations with centrifugal compressors that would be affected by Part 50 based on the number of
3 compressors at that site, not for each individual compressor. The total initial capital cost for
4 installing a degassing system at the 36 compressor sites is \$2,735,150 and the annualized cost of
5 installing a degassing system at the 36 compressor sites is \$667,078.

6 Full details on how these cost equations were applied can be found in the Compressor
7 Seals – Turbines Spreadsheet. *See* NMED Exhibit 66.

Section 20.2.50.115 – Control Devices

8 The requirements of Section 20.2.50.115 apply to control devices used to comply with the
9 emission standards and emission reduction requirements found in Part 50.

Description of Process

11 A control device is any mechanical, thermo, or chemical means to capture, convert,
12 destroy, or recover air contaminants. The purpose of control devices as defined in Part 50 is the
13 reduction of VOCs and NOx. Some control devices are specific to a particular process or type of
14 equipment, while others can be used for multiple processes or types of equipment. The
15 discussion below focuses on those controls outlined in Part 50 and commonly used in oil and gas
16 operations. A brief overview of control devices is provided in this section; for additional
17 discussions of controls for specific processes or types of equipment covered by Part 50, see the
18 testimony for the section of Part 50 that covers the specific process or type of equipment.

19 Examples of control devices include, but are not limited to, open flares, enclosed
20 combustion devices (“ECDs”), thermal oxidizers (“TOs”), vapor recovery units (“VRUs”), fuel
21 cells, condensers, and catalytic converters (oxidative, selective, and non-selective). A control

1 device may also include any other air pollution control equipment or emission reduction
2 technologies approved by the Department to comply with emission standards in Part 50.

3 *Open Flares*

4 Open flares or “flaring” refers to the routing of natural gas from anywhere in the process
5 to a device where the gas is combusted as it leaves the tip of the flare. Flaring is a high-
6 temperature oxidation process used to burn or incinerate waste gases containing combustible
7 components such as VOCs, natural gas (methane), carbon monoxide (CO), and hydrogen (H₂).
8 Flares convert, or destroy, waste gases into less harmful components (ideally, water vapor and
9 carbon dioxide).

10 The flare system consists of a header, stack, tip, and ignition system. Gas is sent to the
11 flare through a header system and is combusted as it exits the flare stack at the tip. The flare tip
12 is designed to ensure the proper mixing of gas and air to achieve the proper burn efficiency.
13 Ignition of the gas stream is through the use of a continuously burning pilot or auto-ignition
14 system. Flaring is a necessary part of drilling and completion activities, oil and natural gas field
15 production, pipeline gas gathering, and facility processing of oil and natural gas because of
16 safety considerations (personnel and equipment) and its effectiveness in combusting harmful
17 emissions (environmental).

18 *Enclosed Combustion Devices*

19 Enclosed combustion devices use a high-temperature oxidation process to control VOCs
20 in many industrial settings because the enclosed combustor can normally handle fluctuations in
21 concentration, flow rate, heating value, and unreactive (i.e., non-combustible) compounds found
22 in the gas stream. For this analysis, it is assumed that the types of combustors installed in the oil
23 and natural gas industry can achieve at least a 95 percent control efficiency on a continuous

1 basis. Combustion devices can be designed to meet a 98 percent control efficiency, and can
2 control emissions by 98 percent on average, or more in practice when properly operated.
3 Combustion devices that are designed to meet a 98 percent control efficiency may not
4 continuously meet this efficiency in practice, due to factors such as variability of field
5 conditions. A typical combustor used to control emissions from storage vessels in the oil and
6 natural gas sector is an enclosed combustion system. The basic components of an enclosed
7 combustion system include (1) piping for collecting emission source gases; (2) a single- or
8 multiple-burner unit; (3) a stack enclosure; (4) a pilot flame to ignite the mixture of emission
9 source gas and air; and (5) combustor fuel/piping (as necessary). Figure 1 presents a schematic of
10 a typical dual-burner enclosed combustion system.

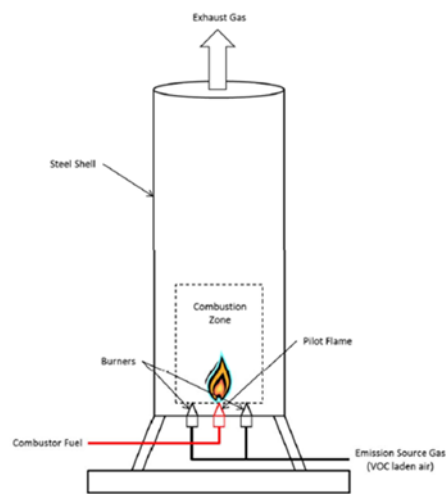


Figure 1 Schematic of a Typical Enclosed Combustion System

13 Thermal oxidizers – also referred to as direct flame incinerators, thermal incinerators, or
14 afterburners – can also be used to control VOC emissions. Similar to a basic enclosed
15 combustion device, a thermal oxidizer uses burner fuel to maintain a high temperature (typically
16 800-850°C) within a combustion chamber. The VOC-laden emission source gas is injected into

the combustion chamber where it is oxidized (burned), and then the combustion products are exhausted (i.e. vented) to the atmosphere. *See* NMED Exhibit 34 (EPA CTG).

Vapor Recovery Units

Vapor recovery units (“VRUs”) route vapors from an emission source back to the inlet line of a separator, to a sales gas line, or to another process line for beneficial use, such as use as a fuel. A VRU is often referred to as a compressor that is used to boost recovered vapors back into the line. In a typical VRU, hydrocarbon vapors are drawn out of the storage vessel under low pressure and are piped to a separator or suction scrubber to collect any condensed liquids, which are recycled back to the storage vessel. Vapors from the separator flow through a compressor that provides the low-pressure suction for the VRU system where the recovered hydrocarbons can be transported to various places, including a sales line and/or for use onsite.

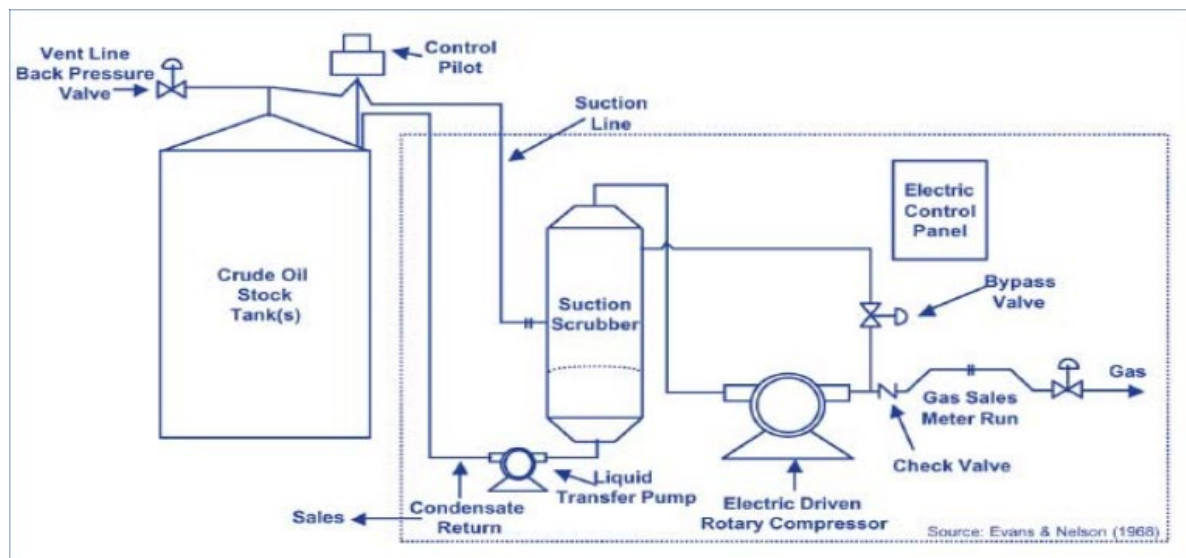


Figure 2 Conventional Vapor Recovery System

1 *Condensers*

2 A condenser is a heat exchanger used to condense a gaseous substance into a liquid state
3 through cooling. Condensers are often used to control VOC emissions from glycol dehydration
4 units by condensing the organic vapors from the regenerator still vent.

5 *Fuel Cells*

6 A fuel cell is an electrochemical cell that converts the chemical energy of a fuel (typically
7 hydrogen but may also be methane or organic vapors) and an oxidizing agent (commonly
8 oxygen) into electricity through oxidation and reduction reactions that convert the fuel into water
9 vapor (in the case of hydrogen fuel) or into carbon dioxide and water vapor (in the case of
10 methane or organic vapors). The use of fuel cells has been investigated as a potential VOC
11 emission control option for the surface coating industry, but has not yet been demonstrated for
12 controlling VOC emissions from oil and natural gas production operations.

13 *Gaseous Emission Control of Stationary Internal Combustion Engines*

14 Gas compressor operations are an essential element of oil and gas production. To produce
15 oil and natural gas and keep natural gas pressures at the level required to move gas from the
16 wellhead to the consumer, compressors and the associated driver are found at multiple locations
17 in the natural gas value chain. In addition to driving compressors, engines may also be used as
18 the driver for power generators that provide electrical power to sites that are not connected to the
19 commercial electrical grid.

20 *Catalytic Converters (oxidative, selective, and non-selective)*

21 Stationary engines, typically fueled by natural gas or propane, are widely used for prime
22 power and for gas compression. In gas compression, the types of engines are either rich-burn or
23 lean-burn. The difference between rich-burn and lean-burn engine operation lies in the air-to-fuel

1 ratio: a rich-burn engine is characterized by excess fuel in the combustion chamber during
2 combustion, while a lean-burn engine is characterized by excess air in the combustion chamber
3 during combustion. For gas transmission, engines are typically lean-burning. Gas engines are
4 also used for prime power applications, especially where it is convenient to connect a natural gas
5 line to the engine. Depending on the application, engines in oil and natural gas operations range
6 in size from relatively small (approximately 50 hp) for certain types of pumps and generators to
7 thousands of horsepower for natural gas compressors at transmission compression stations.

8 Different emission control technologies have to be applied to engines depending on their
9 air-to-fuel ("A/F") ratio. This is because the exhaust gas composition differs depending on
10 whether the engine is operated in a rich, lean, or stoichiometric burn¹⁵ condition. See the
11 previous testimony regarding control options for engines (Section 20.2.50.113) for a discussion
12 of selective catalytic reduction and non-selective catalytic reduction as effective NOx control
13 technologies for engines.

14 Proposed Rule Requirements for Control Devices

15 *General Requirements (Subsection B)*

16 Section 20.2.50.115 requires control devices to be designed, sized, installed, operated,
17 and maintained in order to minimize emissions and achieve the emission standards required by
18 Part 50. Each device must operate as a closed vent system, have an EMT installed, and a monthly
19 inspection is required to ensure proper operation. Closed vent systems must be designed and

¹⁵ In an internal combustion engine or industrial furnace, the air-fuel ratio is an important measure for anti-pollution and performance-tuning reasons. If exactly enough air is provided to completely burn all of the fuel, the ratio is known as the stoichiometric mixture, often abbreviated to stoich. Ratios lower than stoichiometric are considered "rich." Rich mixtures are less efficient, but may produce more power and burn cooler. Ratios higher than stoichiometric are considered "lean." Lean mixtures are more efficient but may cause higher temperatures, which can lead to the formation of nitrogen oxides. Some engines are designed with features to allow lean-burn. For precise air-fuel ratio calculations, the oxygen content of combustion air should be specified because of different air density due to different altitude or intake air temperature, possible dilution by ambient water vapor, or enrichment by oxygen additions.

1 certified by a professional engineer or an in-house engineer. Manufacturer specifications for
2 control devices must be kept on file by the owner or operator and include identifying
3 information, specific operational parameters (e.g., maximum rated capacity) and control
4 efficiency.

5 *Open Flares (Subsection C)*

6 Owners and operators using open flares are required to install a continuous pilot, auto-
7 igniter, or require manual ignition upon start up for new flares, and one year after the effective
8 date of Part 50 for existing flares. All gas sent to the flare must be combusted. For existing flares
9 at facilities with an average daily production of 10 bbls/day of oil or 60,000 scf/day of natural
10 gas, owners and operators are required to install an auto-igniter, continuous pilot, or flare
11 malfunction alarm technology upon replacement or reconstruction. Flares must be operated with
12 no visible emissions, as determined by visual observations or continuous monitoring technology,
13 and all repairs must be completed within three days of an alarm activation.

14 Flares with a continuous pilot must be monitored continuously for the presence of a pilot
15 flame. When an auto igniter is used, the presence of a flame must be continuously monitored
16 during flaring using a thermocouple or alternative equivalent technology approved by the
17 Department. Manually ignited flares must be continuously visually monitored during a flaring
18 event to ensure the flare is lit. Owners and operators are required to perform quarterly EPA
19 Method 22 (40 CFR Part 60, Appendix A) observations to ensure compliance with visible
20 emissions and opacity limits. *See NMED Exhibit 67 – EPA Reference Method 22 – Visual*
21 *determination of Fugitive Emissions from Material Sources and Smoke from Flares* (January 14,
22 2019).

1 Owners and operators of open flares are required to keep records of alarm activation,
2 cause of the alarm, corrective actions, name of personnel conducting the action, and any
3 maintenance activities performed.

4 Owners and operators of open flares must comply with the general reporting
5 requirements in Section 20.2.50.112.

6 *Enclosed Combustion Devices and Thermal Oxidizers (Subsection D)*

7 Enclosed combustion devices and thermal oxidizers (“ECD/TOs”) must be operated
8 within the maximum rated capacity and must combust all gas sent to the equipment. Continuous
9 pilot flames or auto-igniters must be installed upon startup for new ECD/TOs, or within one year
10 for existing ECD/TOs. All ECD/TOs must operate with a continuous flame present and with no
11 visible emissions during flaring events.

12 ECD/TOs with a continuous pilot must be monitored continuously for the presence of a
13 pilot flame. When an auto igniter is used, the presence of a flame must be continuously
14 monitored during flaring using a thermocouple or alternative equivalent technology approved by
15 the Department. Owners and operators are required to perform quarterly EPA Method 22
16 observations to ensure compliance with visible emissions and opacity limits.

17 Owners and operators of ECD/TOs are required to keep records of alarm activation,
18 cause of the alarm, corrective action taken, name of personnel conducting the inspection, and any
19 maintenance activities performed. Additionally, owners and operators must record the results of
20 the quarterly EPA Method 22 observations. Gas analysis results must be recorded for the
21 combustion gas to include the VOC content and heating value.

22 Owners and operators of ECD/TOs must comply with the general reporting requirements
23 in Section 20.2.50.112.

1 *Vapor Recovery Units*

2 All VRUs must be operated as a closed vent system that captures and routes VOC
3 emissions back to the process or to a sales pipeline. Venting to the atmosphere is prohibited and
4 a backup control device (e.g. ECD/TO) or a redundant VRU is required during periods of startup,
5 shutdown, maintenance, or other downtime such as malfunctions.

6 Owners and operators of VRUs must comply with the monitoring requirements for
7 equipment leaks as specified in Section 20.2.50.116, or implement a program that meets the
8 requirements of NSPS Subpart OOOOa.

9 For each VRU inspection or monitoring event, the owner or operator must record the
10 result of the event, including the name of the personnel conducting the inspection, and any
11 maintenance or repair activities required. The owner or operator must also record the type of
12 redundant control device used during VRU downtime.

13 The owner or operator of a VRU must comply with the general reporting requirements in
14 Section 20.2.50.112.

15 Basis for Proposed Requirements for Control Devices

16 The proposed general requirements for control devices in 20.2.50.115.B(1) through (5)
17 are based on similar rules for closed vent systems and control devices in Pennsylvania GP-5 and
18 GP-5A (NMED Exhibits 37 and 38), Colorado Reg. 7, Section II.C.5 (NMED Exhibit 39), NSPS
19 Subpart OOOOa (NMED Exhibit 36), and EPA's NSPS regulations at 40 CFR 60, Subpart A –
20 General Provisions ("NSPS Subpart A").

21 The proposed requirements for closed vent systems for centrifugal compressor wet seal
22 fluid degassing systems in 20.2.50.115.B(6) are based on Colorado Reg. 7, Section I.J.1; and
23 NSPS Subpart OOOOa, Section 60.5380a.

1 The proposed requirements for open flares in 20.2.50.115.C are based on NSPS Subpart
2 OOOOa, Section 60.5412a; and NSPS Subpart A, Section 60.18(b).

3 The proposed requirements for enclosed combustion devices and thermal oxidizers in
4 20.2.50.115.D are based on Pennsylvania GP-5, Section J; Colorado Reg. 7, Sections I.C.1 and
5 II.B.2; NSPS Subpart OOOOa, Section 60.5412a; and NSPS Subpart A, Section 60.18(b).

6 The proposed requirements for VRUs in Section 20.2.50.115.E are based on
7 Pennsylvania GP-5, Section J; and NSPS Subpart OOOOa, Section 60.5412a.

8 Estimated Emissions Reductions

9 The estimated reductions in VOC and NOx emissions from oil and gas operations are
10 discussed in the testimony regarding the proposed requirements for the specific equipment and
11 processes addressed in Part 50. Details on the emissions and emissions reductions are found in
12 the 'Reductions and Costs' spreadsheets for each of the various equipment and process
13 categories regulated under the proposed rule.

14 Estimated Costs

15 The estimated annualized costs of the VOC and NOx emissions reductions resulting from
16 implementation of Part 50 are discussed in the testimony regarding the proposed requirements
17 for the specific equipment and processes addressed in Part 50. Details on the emissions, costs,
18 and reductions are found in the 'Reductions and Costs' spreadsheets for each of the various
19 equipment and process categories regulated under the proposed rule. These costs are specific to
20 the particular equipment/process and the pollutant being controlled.

21 **Section 20.2.50.116 – Equipment Leaks and Fugitive Emissions**

22 Section 20.2.50.116 applies to well sites; tank batteries; gathering and boosting stations;
23 gas processing plants; natural gas compressor stations; and associated piping and components.

1 Description of Equipment and Process

2 The processing of natural gas includes the removal of natural gas liquids from field gas
3 and/or the fractionation of mixed liquids to natural gas products. There are a number of potential
4 sources of equipment leaks during production and processing, such as pumps, pressure relief
5 devices, valves, flanges, and other connectors that have a leak potential due to seal failure. In
6 addition, leaks can occur from open-ended lines and valves as well as from corrosion of welded
7 connections, flanges, and valves. The large number of valves, pumps, and other equipment
8 associated with natural gas production and processing can be a significant sources of VOC
9 emissions.

10 There are also a number of potential sources of fugitive emissions throughout the oil and
11 gas sector. These can occur from poorly fitted connection points or deterioration of seals and
12 gaskets. Fugitive emissions can also be caused by changes in pressure, temperature, or
13 mechanical stresses. A “fugitive emissions component” may be defined as any component that
14 has the potential to emit fugitive emissions at any of the sources previously identified, including
15 valves; connectors; pressure relief devices; open-ended lines; access doors; flanges; closed vent
16 systems; thief hatches or other openings on storage vessels; agitator seals; distance pieces;
17 crankcase vents; blowdown vents; pump seals or diaphragms; compressors; separators; pressure
18 vessels; dehydrators; heaters; instruments; and meters. Devices that would naturally vent as part
19 of normal operations, such as natural gas-driven pneumatic controllers or pumps, are not
20 included as fugitive emissions components. *See* NMED Exhibit 34 (EPA CTG)

21 Control Options for Equipment Leaks and Fugitive Emissions

22 Emissions from fugitive emission sources such as leaking valves, connectors, and flanges
23 can be controlled through implementation of an emission leak detection and repair (“LDAR”)

1 program. In simple terms, LDAR programs reduce emissions by requiring owners and operators
2 to inspect their facilities to find and repair leaks. Leak detection methods include:

- 3 • Audio, visual, and olfactory (“AVO”) inspections;
- 4 • Instrument monitoring according to EPA Reference Method 21, 40 CFR Part 60,
5 Appendix A-7 (“EPA Method 21”); and
- 6 • Monitoring using optical gas imaging (“OGI”).

7 AVO inspections rely on the use of sight, sound, and smell to identify leaking
8 components by listening for hissing or unusual sounds coming from equipment (audio); looking
9 for cracks, holes, visible liquids leaks, or staining (visual); and smelling for unusual or strong
10 odors (olfactory).

11 EPA Method 21 is an established reference method that identifies leaks using a portable
12 instrument that can detect the presence of organic gases and measure their volumetric
13 concentration in parts per million (ppm). The method also allows for the use of a soap solution
14 applied to components that will form bubbles if there is a leak present.

15 OGI is a newer method for leak detection that utilizes forward-looking infrared (“FLIR”)
16 cameras to conduct inspections of equipment components to identify leaks. OGI infrared
17 cameras are highly specialized thermal cameras that can identify methane using its infrared
18 absorption characteristics. OGI cameras can be used to survey large numbers of components in a
19 short amount of time, whereas EPA Method 21 inspections require inspecting one component at
20 a time with the instrument probe.

21 When using EPA Method 21, a leak is detected whenever the measured concentration
22 exceeds the defined concentration threshold standard. In Section 20.2.50.116.C.(4)(c), this is
23 specified as 500 ppm. When using OGI, a leak is detected if the emission images recorded by the

OGI instrument are not associated with normal equipment operation. An owner or operator also has the option of proposing an alternative equipment leak monitoring plan for approval by the department.

The control effectiveness of an LDAR program is based on the frequency of monitoring and the leak definition. More frequent monitoring means that leaks are detected and repaired sooner, so that they emit for a shorter time period, and possibly while they are still small and before they grow larger. A lower ppm leak definition will mean that a larger number of leaks must be repaired than with a higher ppm definition.

Proposed Rule Requirements for Equipment Leaks and Fugitive Emissions

Section 20.2.50.116 sets forth default monitoring requirements that apply to the inspections of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify defects and leaking components. Owners and operators of facilities with an annual average daily production greater than 10 barrels of oil (bbls) per day, or an average daily production greater than 60,000 standard cubic feet per day of natural gas, are required to conduct AVO inspections at least weekly. Facilities with an annual average daily production equal to or less than 10 bbls per day, or an average daily production equal to or less than 60,000 standard cubic feet per day of natural gas, are required to conduct an AVO inspection at least monthly.

Owners or operators of the following facilities must perform inspections using EPA Method 21 (explained above) OGI according to the following schedules:

- **Well sites and tank battery facilities:** annually at facilities with a PTE less than two tpy VOC; semi-annually at facilities with a PTE equal to or greater than two tpy and

1 less than five tpy VOC; and quarterly at facilities with a PTE equal to or greater than
2 five tpy VOC.

- 3 • **Gathering and boosting stations, gas processing plants, and natural gas**
4 **compressor stations:** quarterly at facilities with a PTE less than 25 tpy VOC; and
5 monthly at facilities with a PTE equal to or greater than 25 tpy VOC.

6 Inspections using EPA Method 21 require daily calibration of instruments before use. Regulated
7 leaks are those with a measurement of 500 ppm or greater of hydrocarbons and that not
8 associated with normal operations.

9 Inspections using OGI must comply with the requirements in EPA's regulations at 40
10 CFR Section 60.18. A leak is detected if the emission images recorded by the OGI instrument are
11 not associated with normal equipment operation. Components that are difficult, unsafe, or
12 inaccessible to monitor are not required to be inspected until it becomes feasible to do so.

13 As an equivalent means of compliance with Subsection C of 20.2.50.116, an owner or
14 operator can submit an alternative monitoring plan. The plan must be approved by the
15 Department and can be terminated by the Department if the owner/operator fails to comply with
16 elements of the plan, or fails to correct or disclose a violation within 15 days of discovery.

17 For leaks detected under Section 20.2.50.116, the component must be visibly tagged until
18 repaired and the leak must be repaired within 15 days of discovery, except those detected leaks
19 using OGI, which must be repaired within 7 days of discovery. Equipment must be re-monitored
20 no later than 15 days after discovery of a leak to demonstrate that the leak has been repaired. For
21 leaks that cannot be repaired in the required timeframes above without a process shutdown, the
22 leak may be designated as "Repair Delayed" and repaired before the end of the next process unit
23 shutdown.

1 Owners or operators are required to keep records of the following for all AVO, EPA
2 Method 21, OGI, or alternative equipment leak monitoring inspections conducted pursuant to
3 Section 20.2.50.116: facility location; date of inspection; monitoring method; name of the
4 personnel performing the inspection; description of any leak requiring repair or a note that no
5 leak was found; and whether a visible flag was placed on the leak or not. The owner or operator
6 is required to record any leak detected, the date of detection, and the date of attempted repair. For
7 leaks designated “repair delayed,” the owner or operator must record the reason for delay for
8 leaks not repaired within the allowed time frame, and an authorized representative’s signature
9 who determined the leak could not be implemented without process unit shutdown. The owner or
10 operator must also record information regarding repair and follow-up monitoring. For a leak
11 detected using OGI, the owner or operator must keep records as specified in EPA regulations at
12 40 CFR Section 60.18(i)(1)-(3).

13 Subsection G of 20.2.50.116 requires owners and operators to certify the use of an
14 alternative equipment leak monitoring plan under Subsection D, if used, to the Department
15 annually, and comply with the general reporting requirements in Section 20.2.50.112.

16 Basis for Proposed Rule

17 The requirements in Section 20.2.50.116 are based on similar rules for LDAR programs
18 for oil and gas sources adopted by Colorado and Pennsylvania, and in NSPS Subparts OOOO
19 and OOOOa.

20 Colorado Reg. 7 (NMED Exhibit 39) specifies the following LDAR frequencies for
21 different types of facilities:

- 1 • Natural gas processing plants must comply with the LDAR provisions in NSPS
2 Subpart OOOO, regardless of the age of the facility, unless the facility is subject
3 to NSPS Subpart OOOOa. (Section .I.G).
- 4 • Natural gas compressor stations must perform quarterly instrument monitoring.
5 (Section I.L.1).
- 6 • Well production facilities must perform annual instrument monitoring if
7 uncontrolled actual VOC emissions are equal to or greater than 1 tpy of VOC, but
8 less than or equal to 6 tpy VOC, and must perform semiannual instrument
9 monitoring if uncontrolled actual VOC emissions are greater than 6 tpy VOC.
10 (Section I.L.2).

11 Under Pennsylvania GP-5 and GP-5A for oil and gas operations, all owners and operators
12 of unconventional natural gas well sites, remote pigging stations, natural gas compressor
13 stations, processing plants, and transmission stations must conduct monthly AVO inspections
14 and quarterly inspections using EPA Method 21 or OGI. When using EPA Method 21, a leak is
15 defined as 500 ppm. *See* NMED Exhibits 37 and 38, at pp. 3, 18-19.

16 The equipment leak provisions in NSPS Subpart OOOO apply only to onshore natural
17 gas processing plants and incorporate the provisions of 40 CFR 60, Subpart KKK (Standards of
18 Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants for
19 Which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and
20 on or Before August 23, 2011), which in turn incorporate the provisions of 40 CFR 60, Subpart
21 VV (Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic
22 Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification
23 Commenced After January 5, 1981, and on or Before November 7, 2006).

1 The fugitive emission (i.e., equipment leak) provisions in NSPS Subpart OOOOa, 40
2 CFR § 60.5397a and 60.5400a, require semi-annual inspections using EPA Method 21 or OGI at
3 well-sites, and quarterly inspections at compressor stations and gas processing plants. Well sites
4 that contain only wellheads are exempt from the fugitive emission requirements.

5 Estimated Emissions Reductions

6 Based on the NMED Equipment Data and oil and gas well data from OCD,¹⁶ ERG
7 estimated that there are 23,969 wellhead facilities (based a total well count of 47,937 in the
8 Subject Counties, and assuming an average of 2 wells per wellhead facility), and another 1,950
9 non-wellhead facilities involved in collecting, processing, and transmitting oil and gas. ERG
10 estimated that the non-wellhead facilities have fugitive equipment leak emissions of 7,131 tons
11 per year of VOC, and the wellhead facilities have fugitive equipment leak emissions of 18,894
12 tons per year of VOC. The baseline VOC emissions from equipment leaks at the wellhead
13 facilities and non-wellhead facilities are based on the *Baseline 2014-2016 Oil and Gas Emission*
14 *Inventory for the WESTAR-WRAP Region* (June 2019) (“2014 Oil and Gas Emission Inventory”)
15 attached as NMED Exhibit 68. See NMED Exhibit 69 – LDAR Reductions and Costs VOC
16 Spreadsheet.

17 ERG then evaluated the effect of the proposed requirements on VOC emissions. For non-
18 wellhead facilities, ERG examined the list of 1,950 facilities to determine which facilities were
19 currently implementing an LDAR program under existing federal regulations, which facilities
20 would be required to implement a new LDAR program under Part 50, and what the required
21 frequency of inspection would be for those facilities required to implement a new LDAR

¹⁶ Petroleum Recovery Research Center, GO-TECH website. Oil and gas production data on the PRRC website has been provided primarily by the New Mexico Oil Conservation Division, and is updated on a monthly basis. http://gotech.nmt.edu/gotech/Petroleum_Data/allwells.aspx

program under Part 50, based on the facility type and the facility's total allowable VOC emissions. The total allowable VOC emissions were used as a surrogate for the facility's PTE of VOC. Under NSPS Subparts OOOO and OOOOa, many oil and gas facilities are already required to conduct LDAR. ERG assumed no additional emission reductions would occur at these sources as a result of the proposed rule. The emission reductions expected for each facility implementing a new LDAR program was then estimated based on the following frequency of Method 21 or OGI inspections:

Frequency	Average Percent Reduction (assuming facilities will use a mix of OGI and Method 21)	Inspection Technology
Monthly	92%	Method 21
Quarterly	82%	Method 21/OGI
Semiannually	68%	Method 21/OGI
Annually	54%	Method 21/OGI

These reduction percentages are based on data compiled by EPA in developing updated standards for reducing emissions from equipment leaks for oil and natural gas production sources. *See* NMED Exhibit 70 – EPA, *Background Technical Support Document for the Final New Source Performance Standards (40 CFR Part 60, Subpart OOOOa)*, EPA-HQ-OAR-2010-0505-7631 (May 2016), at page 41 for EPA Method 21 and page 42 for OGI). As a result of this analysis, ERG estimated total emission reductions of 4,654 tons per year of VOC for non-wellhead facilities. *See* NMED Exhibit 69 – LDAR Reductions and Costs VOC Spreadsheet.

For well sites facilities, emission reductions were estimated assuming semi-annual inspections would be required at well sites not currently conducting inspections under existing federal requirements in NSPS Subpart OOOOa. Estimated VOC reductions for well sites that

would be required to implement a new LDAR program under the proposed rule are based on EPA estimates of reductions associated with an LDAR program to be:

Facility Type	Annual VOC Emission Reduction (tpy)
NG Well Site (GOR > 100,000)	0.917
Oil Well Site (GOR < 300)	0.199
Oil Well Site (GOR > 300, < 100,000)	0.451

See NMED Exhibit 34 – EPA CTG, at Table 9-12. As a result of this analysis, ERG estimates total emission reductions of 14,896 tons per year of VOC for well site facilities. See NMED Exhibit 69 – LDAR Reductions and Costs VOC Spreadsheet. This approach would result in total VOC reductions of 14,896 tpy of VOC, which is 79% of the baseline VOC emissions from the New Mexico oil and gas inventory.

Costs of Proposed Requirements

The costs of implementing an LDAR program to reduce fugitive equipment leak emissions are those associated with labor required to conduct inspections and repair leaking components. ERG estimated the costs required to implement a new LDAR program under the proposed rule for well sites based on estimates for well sites from the EPA CTG (NMED Exhibit 34) and from the cost analysis for the 2014 amendments to Colorado Reg. 7. See NMED Exhibit 71 – Colorado Dept. of Public Health and Environment, *Regulatory Analysis for Proposed Revisions to Colorado Air Quality Control Commission Regulation Numbers 3, 6 and 7 (5 CCR 1001-5, 5 CCR 1001-8, and CCR 1001-9)*, (February 11, 2014) (“2014 Colorado Regulatory Analysis”). The LDAR costs for each type of facility were estimated as follows:

Well sites: ERG assumed that all well sites would have two wells, and that all would use semiannual OGI LDAR monitoring. The cost per well site, based on a model plant analysis, was

1 taken from Table 9-12 of the EPA CTG (NMED Exhibit 34). The cost per LDAR inspection was
2 scaled from 2012\$ to 2019\$ using the CEPCI for an annual cost of \$2,375 per site.

3 **Gathering and Boosting Stations:** The cost per gathering and boosting station for
4 quarterly LDAR inspections using OGI, based on a model plant analysis, was taken from Table
5 9-13 of the EPA CTG. The cost per LDAR inspection was scaled from 2012\$ to 2019\$ using the
6 CEPCI for an annual cost of \$26,030 per site.

7 The cost per gathering and boosting station for monthly LDAR inspections was based on
8 the weighted average cost per inspection for LDAR inspections (Table 23) and repairs (Table 24)
9 of the 2014 Colorado Regulatory Analysis. For 359 inspections, the total LDAR costs were
10 \$1,007,064 and the total repair costs were \$523,071. Costs do not include any credit for
11 recovered gas volume. The cost per inspection was multiplied by 12 to obtain the annual LDAR
12 cost. The costs were scaled to 2019\$ using the CEPCI.

13 **Natural Gas Compressor Stations:** The costs for quarterly and monthly LDAR
14 inspections for compressor stations were estimated using the same methodology as that used to
15 estimate the costs of monthly LDAR inspections for gathering and boosting stations as described
16 in the previous paragraph. The annual costs per station were estimated to be \$18,256 for
17 quarterly inspections and \$54,768 for monthly inspections.

18 **Tank batteries:** The cost per LDAR inspection per tank battery includes costs for three
19 elements: (1) a cost per inspection of the closed vent system inspection; (2) a cost per inspection
20 of the tank battery; and (3) the average cost of repairs per inspection. Costs were estimated based
21 on the 2014 Colorado Regulatory Analysis. Costs for storage tank closed vent system inspections
22 are based on 2 hours of a contractor at \$134 per hour per tank battery using EPA Reference
23 Method 21 or an OGI camera. Costs for the tank battery inspection were based on a weighted

1 average cost per inspection in Table 27 of the 2014 Colorado Regulatory Analysis. Costs were
2 scaled from 2013\$ to 2019\$. Costs for repairs were based on the weighted average repair cost
3 per inspection using the total repair cost from Table 28, and the total number of inspections from
4 Table 27, in the 2014 Colorado Regulatory Analysis. *See* NMED Exhibit 71. Costs were in
5 2013\$ and they were scaled to 2019\$ using the CEPCI. The cost per inspection was multiplied
6 by the estimated number of inspections per year required for each tank battery to obtain the total
7 annual cost for each facility of \$1,160 for annual inspections, \$2,319 for semiannual inspections,
8 and \$4,638 for quarterly inspections.

9 **Natural Gas Plants:** The average total number of components (5,947) at a gas plant was
10 taken from Table 8-2 in the EPA CTG (NMED Exhibit 34). The cost per LDAR inspection was
11 estimated assuming a check of 120 components per hour at a cost of \$110/hour for company
12 labor, assuming a “loaded” rate that includes benefits, overhead, vehicle costs, and estimated
13 hourly cost for a purchased EPA Method 21 detector. The hourly labor rate of \$110/hour is from
14 Table 20 on page 41 of the 2014 Colorado Regulatory Analysis (NMED Exhibit 71). The rate of
15 \$103/hr in Table 20 was scaled from 2013\$ to 2019\$ using the CEPCI. The cost per LDAR
16 inspection was multiplied by the estimated number of inspections per year to obtain the total
17 annual cost for each facility of \$21,806 for quarterly inspections and \$65,417 for monthly
18 inspections.

19 The total annualized costs of implementing the LDAR requirements in Part 50 are
20 estimated to be \$2,847,945 for non-wellhead facilities, and \$52,220,185 for well site facilities.
21 Given the emissions reductions expected as a result of the proposed rule, ERG estimated the cost
22 effectiveness of reducing emissions from non-wellhead facilities at \$5,100 per ton of VOC, and
23 \$3,506 per ton of VOC for well site facilities.

Section 20.2.50.117 – Natural Gas Well Liquid Unloading

Applicability

The requirements of Section 20.2.50.117 apply to liquid unloading operations including down-hole well maintenance events at natural gas wells.

Process Description and Control Options for Natural Gas Well Liquid Unloading

Liquids unloading is used to remove accumulated fluids in the wellbore of a natural gas production well. Managing wellbore liquid build-up in gas wells is fundamental to maintaining production, avoiding early abandonment of wells, and maximizing resource recovery. Wells and reservoirs follow a continuum of flow regimes in their economic life as the reservoir depletes, production declines, wellbore (tubing) velocity goes down, and liquid loading begins to occur in the wellbore. Liquid loading begins when the gas velocity up the production string is not sufficient to lift liquids up to the surface at a pressure that will allow gas production to overcome the surface equipment and flow out of the wellbore. While pressure is a factor, it is generally a lack of velocity that causes liquids to accumulate in the wellbore (i.e., to “load” or “load up”).

New wells typically have sufficient production rates and flowing velocity so that liquids loading is not an issue. As the portion of the reservoir accessed by a well depletes, the production rate and velocity declines and eventually a point is reached where liquids loading begins to be an issue. The time at which liquids loading occurs is dependent on the reservoir characteristics, and varies from well to well.

At the onset of liquids unloading, techniques that rely on the reservoir energy are typically used to remove liquids. The following techniques can be used individually or in combination to manage wellbore liquids and maintain production:

- 1 • **Intermitting:** Shutting in a well (i.e., stopping or reducing production) for a period of
2 time to allow the reservoir near the wellbore to “refill” the pressure and volume “void” so
3 that when the well is restarted the production rate and velocity are higher and the well can
4 “unload” liquids through the normal production route to sales;
- 5 • **Velocity strings:** Installing a smaller diameter tubing string in the well that increases the
6 flow velocity at a given production rate sufficiently to drag liquids up the wellbore and
7 prevent liquid loading; and
- 8 • **Surfactants and foaming agents:** Introducing surfactants and foaming agents to the
9 bottom of a well (various techniques are used) creating foam with lower specific gravity
10 which enables liquids to be carried up the wellbore at lower velocities.

11 Eventually a well will reach a point where the reservoir energy is not sufficient to remove
12 the liquids from the well and adding energy to the well is necessary to continue production.

13 Three common methods are:

- 14 • Installing a plunger lift system, which uses differential pressure between the bottom-hole
15 and the surface/gas collection line instead of velocity to remove liquids. A plunger lift
16 consists of a plunger that is dropped down the well bore when the gas pressure declines to
17 a predetermined set point. A valve on the plunger allows gas and liquid to pass through
18 the plunger as it falls. When the plunger reaches the bottom, the valve is automatically
19 closed, and gas pressure in the well below the plunger accumulates until the plunger and
20 fluid column above it are lifted to the top of the well bore. The plunger is caught at the
21 top of the well bore and held until the gas pressure decreases to the point the plunger is
22 released down into the well, and the cycle is repeated. The plunger lift can be operated
23 automatically, and it eliminates the need to vent the well unload fluids.

- Installing wellhead compression that lowers the surface back-pressure on a well to increase the differential pressure between the reservoir and the collection/sales line, and therefore increase production rate and flow velocity.
- Installing a downhole positive displacement reciprocating rod pump with a surface pumping unit to pump liquids from the well bore, or installing a submersible electric liquids pump. These options (sometimes referred to as “artificial lift”) are generally used when there is insufficient pressure to operate a plunger lift. These pumping units can eliminate the need to vent the well to unload fluids.

There are a number of different pump types and gas lift systems, each more effective in some respects than others. Installation of a system to add energy to a well is an economic decision based on whether the continuing production will be sufficient to support the costs of installing and operating a pump or gas lift system.

VOC emissions from liquids unloading operations occur when the well is vented to the atmosphere to unload fluids or when the liquids are unloaded through atmospheric tanks and the gas mixed with the liquid is vented to the atmosphere. To reduce emissions and waste of gas during manual (i.e., non-automated) liquids unloading activities, operators can monitor manual liquids unloading events onsite within close proximity to the well or via remote telemetry to ensure that the well returns to normal production operation as soon as possible.

Proposed Rule Requirements for Liquids Unloading

Section 20.2.50.117 requires the owner or operator of a natural gas well to use the following best management practices during liquid unloading to minimize emissions, consistent with well site conditions and good engineering practices:

- Reduce wellhead pressure before blowdown;

- 1 • Monitor manual liquid unloading in close proximity to the well or via remote
- 2 telemetry; and
- 3 • Close well head vents to the atmosphere and return the well to normal production
- 4 operation as soon as practicable.

5 The owner or operator of a natural gas well is required to use one of the following
6 methods to reduce emissions during an unloading event:

- 7 • Installation and use of a plunger lift;
- 8 • Installation and use of artificial lift (e.g., a positive displacement rod pump or a
- 9 submersible pump); or
- 10 • Installation and use of a control device.

11 Monitoring, recordkeeping, and reporting requirements are proposed to ensure the owner
12 or operator is properly performing liquid unloading operations and down-hole well maintenance
13 in a manner that meets the emissions reduction requirements in Part 50. The monitoring
14 requirements include monitoring well-head parameters and performing VOC volume and mass
15 calculations during an unloading event. Owners and operators are required to maintain records of
16 well location and ID number, liquid unloading dates, wellhead pressure, vented gas flow rate (to
17 the extend feasible), duration of venting event, VOC management practice used before and
18 during liquid unloading, device used to control VOC emissions during unloading, and calculation
19 of VOC emissions vented during unloading. The VOC calculation is based on the duration,
20 volume, and mass of the VOC.

21 Owners and operators must also comply with the general monitoring, recordkeeping, and
22 reporting requirements in Section 20.2.50.112.

1 Basis for Proposed Requirements

2 The proposed operational requirements and best management practices for limiting VOC
3 emissions during natural gas well liquids unloading events are based on requirements in
4 Colorado Reg. 7, Pennsylvania GP-5 and GP-5A, and the Wyoming Permitting Guidance.

5 Colorado Reg. 7, Sec. II.G.1, requires owners and operators to “use best management
6 practices to minimize hydrocarbon emissions and the need for emissions from the well
7 associated with ..., well liquids unloading, ... unless emitting is necessary for safety.” The
8 owner/operator must first use any means of creating differential pressure to attempt to unload the
9 liquids from the well without emitting; if these methods are not successful, the well is permitted
10 to emit to the atmosphere in order to create the necessary differential pressure to bring the liquids
11 to the surface. The owner/operator is required to “be present on-site during any planned well
12 liquids unloading and must ensure that any emissions from the well associated with the event are
13 limited to the maximum extent practicable.” Finally, the owner/operator is required to keep
14 records of the unloading event, as well as an estimate of the amount of emissions. *See* NMED
15 Exhibit 39.

16 Pennsylvania GP-5 and GP-5A, Condition 2.L.1, requires the owner/operator conducting
17 wellbore liquids unloading operations to:

18 [U]se best management practices including, but not limited to, plunger lift
19 systems, soaping, swabbing, unless venting is necessary for safety to mitigate
20 emissions during liquids unloading activities. In all cases, where technically
21 feasible and safe, the owner or operator shall direct the gas generated during
22 liquids unloading to a control device, a gas production line or existing separator or
23 storage vessel which is controlled.

24 The owner or operator is also required to keep records of each liquids unloading operation,
25 including the technique used, the disposition of the associated gas, the duration of the event, and
26 an estimate of the emissions. *See* NMED Exhibits 37 and 38.

1 The Wyoming Permitting Guidance requires that owners/operators minimize VOC
2 emissions to the extent practicable during manual and automated blowdown/venting episodes
3 associated with liquids unloading. Personnel are required to remain on site to ensure minimal gas
4 venting occurs during manual blowdown or venting. The Guidance states that permits will
5 include requirements to keep records of the unloading event, as well as an estimate of the
6 emissions. *See* NMED Exhibit 40, at p. 13.

7 Estimated Emissions Reductions

8 Emission estimates for liquid unloading operations were included in the emissions
9 inventory used in the ozone modeling conducted as part of this rulemaking. The inventory
10 estimated 13,020 tpy of VOC emitted from gas well liquids unloading events. No data on liquid
11 unloading operations are found in the NMED Equipment Data.

12 A review of EPA's 2019 Greenhouse Gas Reporting Program Data (40 CFR part 98,
13 Subpart W) indicated that 97% of gas wells in the Permian and San Juan basins that require
14 liquids unloading currently employ plunger lifts.¹⁷ These data are summarized in the following
15 table.

¹⁷ GHGRP data available at: <https://enviro.epa.gov/index.html>

Subpart W-2019 Liquids Unloading Data for San Juan and Permian Basins in New Mexico

Parameter	San Juan - NM	Permian - NM	Totals
Total # Gas Wells	17,536	2,929	
% of gas wells requiring liquids unloading	26.4%	2.2%	
% of gas wells requiring liquids unloading - Vent Using Plunger Lifts	25.9%	0.3%	
% of gas wells requiring liquids unloading - Vent Without Using Plunger Lifts	0.5%	1.9%	
Wells that require liquids unloading that have a plunger lift			
# Wells With Plunger Lift	4,544	10	4554
% With Plunger Lift	98%	15%	97.1%
Wells that require liquids unloading that do not have a plunger lift			
# Wells - Non-Plunger Lift	82	55	137
% Non-Plunger Lift	2%	85%	2.9%

A 2016 analysis estimated that installation of plunger lifts would reduce emissions by 95%. *See* NMED Exhibit 72 - ICF International, *Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems*, (May 2016) (“ICF Economic Analysis”). Using this estimated percentage reduction, ERG estimated that installation of plunger lifts on the remaining 2.9% of wells requiring liquids unloading that currently do not employ this technology would result in reductions of 4,272 tpy of VOC, or 36% of the baseline VOC emissions.

No estimates are available to quantify the reductions expected from implementation of the proposed best management practices requirements under Part 50.

Estimated Costs

Section 20.2.50.117 requires the use of best management practices to minimize the frequency of and emissions from natural gas well liquids unloading events. The rule also requires an owner or operator to use plunger lifts, artificial lift (i.e., positive displacement pumps or submersible pumps), or a control device during liquids unloading events to minimize emissions. The ICF Economic Analysis estimated that costs associated with installation of a plunger lift include capital costs of \$20,000 and operating costs of \$2,400. *See* NMED Exhibit 72, at p. 2-8.

1 In a 2011 report, EPA estimated that the payback period for installing a plunger lift could be
2 from 1 to 8 years, depending on the value of natural gas and well-specific parameters. *See*
3 NMED Exhibit 73 – EPA report, *Lessons Learned from Natural Gas STAR Partners – Options*
4 *for Removing Accumulated Fluid and Improving Flow in Gas Wells* (2011). EPA has further
5 found that the advantages of a plunger lift, in addition to reduced VOC and methane emissions,
6 include increased productivity and reduced well maintenance, such as treatments to remove scale
7 and paraffin. *See* NMED Exhibit 74 – EPA report, *Lessons Learned from Natural Gas STAR*
8 *Partners – Installing Plunger Lift Systems in Gas Wells* (2006).

9 **Section 20.2.50.118 – Glycol Dehydrators**

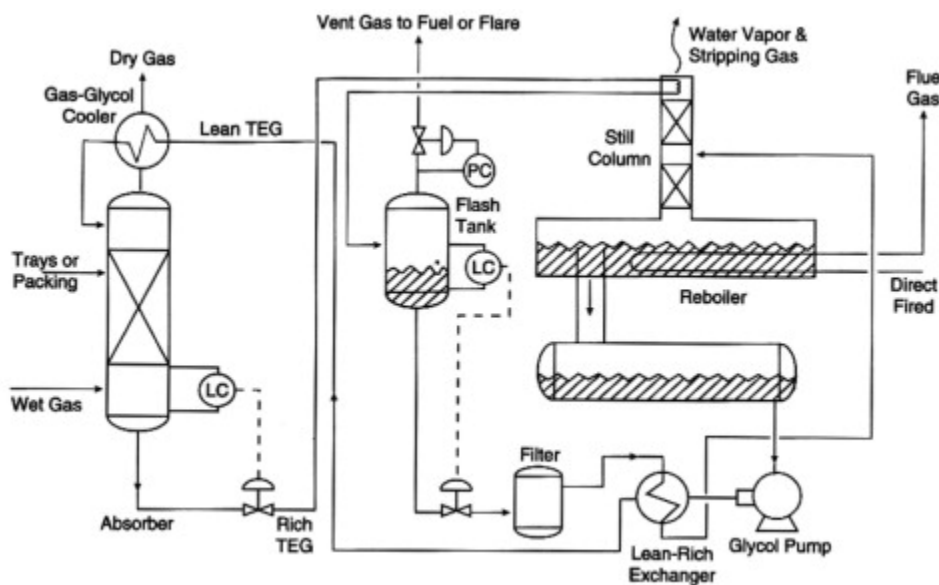
10 Applicability

11 Section 20.2.50.118 applies to glycol dehydrators with a PTE equal to or greater than two
12 tons per year of VOC and are located at well sites, tank batteries, gathering and boosting stations,
13 natural gas processing plants, and natural gas compressor stations.

14 Description of Glycol Dehydrator

15 A glycol dehydrator is a liquid desiccant system for the removal of water from natural
16 gas and natural gas liquids. Triethylene glycol is the most commonly used desiccant in these
17 systems. Failure to remove water results in formation of crystalline hydrates at the high pressures
18 used to transport the gas. Hydrates can block pipelines, jam valves, and can generally wreak
19 havoc on pipeline equipment and instrumentation. In the glycol dehydrator, the triethylene glycol
20 absorbs water and VOCs from the gas. The triethylene glycol is then regenerated by heating it to
21 release the absorbed compounds. The reboiler from a large glycol dehydrator can discharge more
22 than one hundred tons per year of VOCs, including benzene, toluene, ethylbenzene and xylene
23 (collectively known as “BTEX”).

The actual setup of a glycol dehydrator system can vary amongst manufacturers, but the following description outlines the basics. Wet gas typically passes first through an inlet separator to remove natural gas liquids, which are then stored prior to further processing to separate the components of the gas. The wet gas is introduced into the bottom of a contact tower, and dry, lean glycol flows down the tower from the top. Contact of the two streams is enhanced through the use of tower trays or packing material. The inlet gas is stripped of water and VOCs as it travels up the tower, and becomes drier as it rises. The glycol absorbs more water as it travels down the tower, becoming “rich” or wet glycol. The dehydrated gas, may at this point, pass through a heat exchanger with lean glycol to reduce the temperature of the dry, lean glycol from the surge tank before it is introduced to the contact tower. The dry gas is returned to the pipeline as pipeline-quality natural gas, or goes to other processing units for the recovery of natural gas liquids. The rich glycol exits the tower at the bottom and passes through a filter prior to entering the glycol pump to help reduce wear on the glycol pump.



(Image from ScienceDirect.com)

1 After leaving the glycol pump, the rich glycol may enter a phase separator, also referred to as a
2 flash tank. As the rich glycol enters the flash tank, its pressure is reduced to atmospheric
3 pressure, and the glycol is separated from contaminants, lubricating oil, free water and
4 condensate. The flashed gas, comprised of VOCs, exits through a vent to atmosphere, or is used
5 as fuel, flared, or used as a stripping gas to aid in the regeneration process.

6 The glycol regenerator, or reboiler, is comprised of two pieces – the reboiler and surge
7 tank. The reboiler is gas-fired, and is equipped with a baffle to ensure that the glycol contained
8 inside covers the fire tube. Burner exhaust is vented to the atmosphere, and consists of products
9 of combustion.

10 The rich glycol enters the regenerator through a packed still column. The rich glycol hits
11 the preheated glycol in the reboiler, and water flashes off as steam and goes back through the still
12 column, while the glycol drops back into the reboiler. The regenerated glycol then flows over the
13 baffle and into the surge tank. From the surge tank, the lean glycol is pumped back to contact
14 tower for reuse.

15 The regenerator off-gas is either vented to the atmosphere, or sent to a condenser or
16 thermal oxidizer. Because of their high solubility, most of the BTEX compounds are not flashed
17 from the glycol at the flash tank, but instead are separated from the glycol in the regenerator.

18 Control Options for Glycol Dehydrators

19 There are a number of options available to owners and operators of glycol dehydrators for
20 controlling emissions. Still vent and flash tank emissions can be routed at all times to the reboiler
21 firebox (for use as fuel), a condenser, combustion control device, to a process point that either
22 recycles or recompresses the emissions or uses the emissions as fuel, or to a vapor recovery unit
23 (VRU) that reinjects the VOC emissions back into the process stream or a natural gas gathering

1 pipeline. See testimony regarding control devices (Section 20.2.50.115) for a discussion of
2 VRUs. A combustion control device is either a flare or an enclosed combustor. A condenser uses
3 water, air, or another coolant to lower the temperature of the vent gases and cause the vapors to
4 condense from gas to liquid phase where they can be collected. Costs were estimated for
5 condensers and combustion control devices because existing cost estimates are readily available
6 and are more universally applicable. Costs for other control options are more site-specific and
7 standardized cost estimating methods are not readily available.

8 Proposed Rule Requirements for Glycol Dehydrators

9 Section 20.2.50.118 requires owners and operators of existing dehydrators with a PTE
10 greater than 2 tpy VOC are required to reduce VOC emissions from the still vent and flash tank
11 by at least 95% no later than two years after the effective date of the rule. Owners and operators
12 of new glycol dehydrators with a PTE greater than 2 tpy VOC are required to reduce VOC
13 emissions from the still vent and flash tank by at least 95% upon startup. For both new and
14 existing dehydrators, the combustion device (if used) must meet a minimum 98% destruction
15 efficiency.

16 Still vent and flash tank emissions must be routed to a control device, a process point that
17 either recycles or recompresses the emissions or uses the emissions as fuel, or to a VRU that
18 reinjects the VOC emissions back into the process stream or natural gas gathering pipeline. If a
19 VRU is used, the VRU must be operational at least 95% of the time, resulting in a minimum
20 combined capture and control efficiency of 95%. The requirements of Section 20.2.50.118 cease
21 to apply when the uncontrolled actual annual VOC emissions from a new or existing glycol
22 dehydrator are less than 2 tpy VOC.

1 Section 20.2.50.118 contains monitoring, recordkeeping, and reporting requirements that
2 ensure affected sources are being properly operated and maintained in a manner that meets the
3 emissions reduction requirements in Part 50. The monitoring requirements include conducting an
4 annual extended gas analysis to determine the composition of the gas being processed by the
5 dehydrator. Owners and operators are required to use this gas analysis to calculate the
6 uncontrolled and controlled emissions from the dehydrator. This calculation will demonstrate
7 whether the 95% emission reduction requirement is met.

8 Owners and operators are required to inspect dehydrators and control devices or
9 processes semi-annually to ensure integrity of the equipment and that the equipment is being
10 operated as initially designed and in accordance with manufacturers specifications.

11 Owners and operators must also meet the monitoring requirements of Sections
12 20.2.50.112 (general requirements) and 20.2.50.115 (control devices).

13 Records of equipment throughput data, emissions calculations and supporting
14 documentation, inspection results, and manufacturer information are required to be maintained
15 onsite and submitted to the Department upon request.

16 Basis for Proposed Requirements

17 The proposed requirements in Section 20.2.50.118 are based on similar requirements for
18 dehydrators adopted by Colorado and Pennsylvania, as well as federal regulations. The
19 applicability threshold of 2 tpy of VOC is based on the applicability threshold for individual
20 dehydrators in Colorado Reg. 7, Sec. II.D). However, Section 20.2.50.118 does not incorporate
21 the Colorado applicability specification that the total VOC from all dehydrators at a site
22 (counting only those with VOC emissions greater than or equal to 1 tpy) must also be greater
23 than or equal to 15 tpy. If the site-wide applicability threshold of 15 tpy used in Colorado were

1 adopted in Part 50, the number of sites with glycol dehydrators subject to regulation would be
2 reduced by about 60 percent, but the total VOC from glycol dehydrators subject to regulation
3 would be reduced by 25 percent. Therefore, the Department is proposing an applicability
4 threshold of 2 tpy VOC emissions per dehydrator in order to maximize potential VOC
5 reductions. *See* NMED Exhibit 75 – Dehydrator 15 tpy Cutoff Analysis Spreadsheet.

6 Pennsylvania GP-5 and GP-5A, both at Section B, have a threshold of greater than or
7 equal to 2.7 tpy for dehydrators. *See* NMED Exhibit 37, at p. 11; NMED Exhibit 38. at p. 10.

8 The proposed capture and control efficiency of 95% for emissions from an uncontrolled
9 dehydrator's still vent and flash tank is taken from the federal National Emissions Standards for
10 Hazardous Air Pollutants ("NESHAP") regulations for emissions from glycol dehydrators, 40
11 CFR Part 63, Subpart HH ("NESHAP Subpart HH"), Section 63.765, requiring controls for
12 VOCs.

13 Emissions from dehydrators are typically controlled with either a condenser or a
14 combustor (enclosed flare).

15 Estimated Emissions Reductions

16 The NMED Equipment Data indicates that there are 571 active glycol dehydrators
17 located in the Subject Counties, or that are considered "Portable" units. Of these dehydrators,
18 341 glycol dehydrators at 230 unique sites have allowable emissions equal to or greater than 2
19 tpy of VOC. The NMED Equipment Data indicates that 199 of these dehydrators currently do
20 not have VOC emissions controls, and of these 199 dehydrators, 93 are not subject to NESHAP
21 Subpart HH; thus, those 93 dehydrators would be required to control emissions under Part 50.
22 For uncontrolled dehydrators that are subject to NESHAP Subpart HH, ERG assumed that these
23 facilities are complying with those regulations by optimizing the glycol recirculation rate, which

1 the background document for NESHAP Subpart HH assumed would reduce emissions by 48%.
2 ERG assumed that facilities without add-on controls and not subject to NESHAP Subpart HH
3 would achieve a 95% emission reduction, and the uncontrolled facilities subject to NESHAP
4 Subpart HH would achieve an incremental emission reduction of 47% (i.e., 95% - 48%) by
5 installing add-on controls. An emission reduction of 0% was assumed for dehydrators that
6 already have add-on controls for VOC. *See* NMED Exhibit 76 – Memo from Heather Brown,
7 P.E., to Greg Nizich, *Impacts of Applying Management Practices to a Single Oil and Natural*
8 *Gas Production Area Source Facility*, EPA Docket No. EPA-HQ-OAR-0238-0061 (December
9 21, 2006) at Table 1.

10 Adding controls to dehydrator units would reduce emissions by 1,865 tpy, leading to a
11 46.2% overall reduction in VOC emissions from dehydrators. These reductions are calculated
12 starting from a baseline calculated as the total allowable emissions for all 577 dehydrators. *See*
13 NMED Exhibit 77 – Dehydrators Reductions and Costs Spreadsheet.

14 Estimated Costs

15 The annualized costs of emission reductions for glycol dehydrators were calculated by
16 applying the control costs for either condensers or combustors to each of the 199 uncontrolled
17 dehydrators. Condenser costs are taken from two memos in the EPA rulemaking docket for the
18 2007 amendments that added regulations for dehydrators at lower emitting “area” source facilities
19 to the existing regulations for higher emitting “major” source facilities, codified at 40 CFR 63,
20 Subpart HH. *See* NMED Exhibit 78 – Memo from Heather Brown, P.E., to Greg Nizich, *Revised*
21 *Impacts from Area Sources in the Oil and Natural Gas Production Source Category*, EPA Docket
22 No. EPA-HQ-OAR-2004-0238-0002 (June 25, 2005); NMED Exhibit 79 – Memo from Heather
23 Brown, P.E., to Greg Nizich, *Impacts of the Final Standards for Oil and Natural Gas Production*

1 *Area Sources*, EPA Docket No. EPA-HQ-OAR-2004-0238-0055 (December 21, 2006). Those
2 costs were updated to 2019 costs using the CEPCI. Combustor costs are taken from the 2018
3 Technical Support Document for the rulemaking proceedings on Pennsylvania GP-5 and GP-5A.
4 *See* NMED Exhibit 52. These costs were updated to 2019 costs using the CEPCI.

5 Based on ERG's research and analysis, the annualized cost for installing and operating a
6 condenser is estimated to be \$21,560. The annualized cost for installing and operating a combustor
7 is estimated to be \$10,583. The total annualized costs of adding condensers to the 199 dehydrator
8 units would be approximately \$4,300,000 per year, while the total annualized costs of adding
9 combustors to the 199 dehydrator units would be approximately \$2,100,000 per year. Costs for
10 both condensers and combustion controls are presented for information purposes, although for
11 each dehydrator the owner of operator would install either a condenser or a combustor, not both.

12 **Section 20.2.50.119 – Heaters**

13 Applicability

14 Section 20.2.50.119 applies to natural gas-fired heaters with a rated heat input equal to or
15 greater than 10 MMBtu/hour including heater treaters, heated flash separators, evaporator units,
16 fractionation column heaters, and glycol dehydrator reboilers in use at well sites, tank batteries,
17 gathering and boosting stations, natural gas processing plants, and natural gas compressor
18 stations.

19 Description of Equipment and Process

20 Natural gas-fired heaters are used throughout the oil and gas production and processing
21 sectors to prevent equipment from freezing and being blocked by the formation of ice or
22 hydrates; to improve the separation of well products into oil, water, and natural gas; and in
23 certain types of process equipment, such as glycol dehydrators.

1 A 'heater treater' is a heated vessel that separates the natural gas and liquids coming from
2 a well into a natural gas stream, an oil/condensate stream, and a produced water stream. The
3 heater treater uses heat to break the oil/condensate-water emulsion coming from the well so the
4 oil/condensate can be accepted by the pipeline or for tanker transport.

5 Heaters may also be used to prevent the formation of ice and natural gas hydrates that can
6 form under the high pressures associated with the gas well production process. These solids can
7 plug the wellhead and other equipment where there is a drop in pressure and/or temperature as
8 the liquids and gas are removed from the well and processed downstream. Since the wellhead is
9 fitted with a device (a "choke") to restrict the flow of the oil and gas from the well, temperatures
10 within the wellhead may drop due to the pressure changes caused by the choke – i.e., as the gas
11 pressure drops, the temperature of the equipment also drops and can reach temperatures well
12 below freezing. This may cause the water or hydrates to freeze and plug the wellhead, resulting
13 in slowing or stopping the condensate and gas production.

14 Heaters are also used to regenerate certain process materials used in oil and gas
15 production so they can be used again. For example, a heater is used in ethylene glycol
16 dehydrators to remove water from the glycol by heating the glycol and causing the water to
17 evaporate from the glycol. Heaters are also used to regenerate dry desiccants (water absorbing
18 materials) that are used in some types of natural gas dehydrators in place of ethylene glycol.

19 Natural gas-fired hot oil (or thermal) heaters may be used in combination with heat
20 exchangers to warm a secondary fluid that may be gas or liquid, for example amine that is used
21 in gas processing plants for the removal of H₂S and CO₂ from field gas. Hot oil heaters may also
22 be used to provide heat for regenerative gas heaters which are used to drive water from
23 molecular sieves within the gas dehydration process.

Control Options for Heaters

NO_x emissions from heaters may be controlled through combustion modifications that reduce the formation of NO_x; through the use of add-on controls to control NO_x in the exhaust stack; or through a combination of combustion modifications and add-on controls. Combustion modifications include low-NO_x burners (“LNBS”), ultra-low NO_x burners (“ULNBS”), and flue gas recirculation (“FGR”). Add-on controls include selective noncatalytic reduction (“SNCR”) and selective catalytic reduction (“SCR”). In addition to combustion modifications and add-on controls, many regulatory programs require periodic equipment tune-ups and good combustion practices to keep heaters operating at maximum efficiency in order to reduce emissions. Good combustion practices are also important in controlling CO and VOC emissions.

Proposed Rule Requirements for Heaters

Section 20.2.50.119 limits existing and new natural gas-fired heaters to 30 ppmvd NO_x at 3% oxygen, and 300 ppmvd CO at 3% oxygen. Existing heaters must comply with these standards no later than one year after the effective date of Part 50, while new heaters must comply upon startup. Owners and operators of heaters subject to this Section are required to install an EMT on the heaters in accordance with Section 20.2.50.112.

Owners and operators are required to conduct emission testing for NO_x and CO within 180 days of the applicable compliance date, and at least every two years thereafter. The equipment must be inspected, maintained, and repaired in accordance with the manufacturer’s specifications at least once every two years after the applicable compliance date. An owner or operator may deviate from the specified periodic testing procedures by submitting a written request to use an alternative procedure to the Department at least 60 days prior to performing the periodic testing, but must receive written approval from the Department prior to conducting periodic testing using an alternative procedure.

1 Owners and operators are required to maintain records of the following information: location
2 of the heater; summary of the complete test report and results of periodic testing; and inspections,
3 testing, maintenance, and repairs. The owner or operator must comply with the general reporting
4 requirements in Section 20.2.50.112.

5 Basis for Proposed Requirements

6 The proposed NO_x and CO limits are based on limits adopted by the State of
7 Pennsylvania and EPA for natural gas fired combustion units. The NO_x limits are the same as
8 those in the Pennsylvania GP-5 requirements for natural gas-fired combustion units. *See* NMED
9 Exhibit 37 at Section L, p. 24. The CO limits are the same as those in the federal regulations at
10 40 CFR 63, Subpart DDDDD, *National Emission Standards for Hazardous Air Pollutants for*
11 *Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters*
12 *(“NESHAP Subpart DDDDD”)*. *See* NMED Exhibit 80. CO is commonly regulated as a
13 surrogate for VOC or organic hazardous air pollutants (“HAP”) because CO is a good indicator
14 of incomplete combustion and VOC and HAP are products of incomplete combustion. EPA used
15 CO limits instead of hazardous air pollutant limits in NESHAP Subpart DDDDD because it
16 “concluded that CO, which is less expensive to test for and monitor, is appropriate for use as a
17 surrogate for non-dioxin organic HAP.” *See id.*, at p. 52210.

18 Estimated Emissions Reductions

19 Based on the NMED Equipment Data, ERG identified 337 facilities with heaters in the
20 Subject Counties, and heaters that are listed as portable heaters. These heaters include separator
21 heaters, heater treaters, glycol dehydrator reboilers, and fractionation column heaters. The data
22 include 698 heaters with annual allowable NO_x emission limits that were used to estimate
23 emissions reductions. The total allowable NO_x emissions from these 698 heaters are 1,355 tpy
24 NO_x, and this was considered the baseline. Of the 698 heaters, 82 have a heat input equal to or

greater than 10 MMBtu/hour and would be subject to Part 50. These 82 heaters have total allowable NO_x emissions of 799 tpy.

ERG then examined the effect of implementing the proposed regulations on reducing NO_x emissions. For purposes of this analysis, ERG assumed that there would be no additional reductions for units already subject to a federal New Source Performance Standard (“NSPS”). For any non-NSPS units, ERG estimated NO_x reductions of 50%, based on the use of low-NO_x burners (“LNB”). See NMED Exhibit 81 – EPA, *Technical Bulletin: Nitrogen Oxides (NO_x), Why and How They Are Controlled* (November 1999), at Table 16.

As a result of this analysis, ERG estimated total reductions of 216 tons per year of NO_x for an overall reduction of 16% from the baseline of 1,355 tpy NO_x. See NMED Exhibit 82 – Heaters Reductions and Costs NO₂ Spreadsheet.

Estimated Costs

ERG calculated estimated annualized costs to meet the proposed emission limits by assuming that all non-NSPS units would need to install LNB technology at an estimated average total annual cost of \$9,250 (\$1991) per heater, according to the EPA’s Alternative Control Techniques Document – NO_x Emissions from Process Heaters, Table 6-2 – NO_x Emissions from Process Heaters See NMED Exhibit 109, EPA Office of Air Quality and Standards, *Alternative Control Techniques Document – NO_x Emissions from Process Heaters*, EPA 453/R-93-034 (September 1993) (excerpt), p. 6-13. These costs were updated to reflect 2019 costs of \$15,553 per heater using the CPECI of 361.3 for 1991 and 607.5 for 2019. The 2019 annualized cost per heater is therefore estimated as:

$$\text{\$9,250 per heater} * (607.5/361.3) = \text{\$15,533 per heater.}$$

Based on the NMED Equipment Data, a total of 44 units would require this technology, for a total annualized cost of approximately \$684,341. Based on the emissions reductions of 216.4 tons per year of NO_x, the cost effectiveness of reducing emissions through the use of LNB to meet the required emission limits would be \$3,162 per ton of NO_x reduced.

Section 20.2.50.120 – Hydrocarbon Liquid Transfers

Applicability

Section 20.2.50.120 is applicable to hydrocarbon liquid transfer operations (or hydrocarbon liquid loading) at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and natural gas compressor stations.

Description of Process

Hydrocarbon liquid transfers involve moving hydrocarbon liquid from a transfer vessel to a storage tank, or from a storage tank to a transfer vessel. There are three primary methods of vessel loading: splash loading, submerged fill pipe,¹⁸ and bottom loading. For splash loading, the fill pipe is lowered only part way into the vessel, and the resultant splashing generates VOC emissions. In submerged fill pipe loading, the fill pipe will extend close to the bottom of the vessel. In bottom loading, a permanent fill pipe is connected at the bottom of the vessel. Both submerged fill pipe loading and bottom loading reduce the generation of VOC emissions. During the transfer of hydrocarbon liquids from one vessel to another, the remaining VOC-containing vapor from the previous contents of the vessel will also be vented as the vessel is filled.

Control Options for Hydrocarbon Liquid Transfers

The options typically used to reduce VOC emissions from hydrocarbon liquid transfers are similar those for storage tanks, and include:

¹⁸ A pipe inserted into a tank to facilitate loading.

- 1 (1) route emissions from the storage vessel through an enclosed system to a process
2 where emissions are recycled, recovered, or reused in the process – “route to a
3 process” (e.g., by installing a vapor recovery unit (VRU) that recovers vapors from
4 the storage vessel) for reuse in the process or for beneficial use of the gas onsite;
5 and/or
6 (2) route emissions from the storage vessel to a combustion device.

7 In practice, many operators use a single, common VRU system or combustion device to control
8 emissions from both hydrocarbon liquid transfers and storage tanks.

9 In addition to these control options, emissions from hydrocarbon liquid transfers are also
10 commonly controlled using vapor balancing service, whereby the vapors in the tanker truck or
11 railcar are routed back into the storage vessel as the liquids in the storage vessel are emptied into
12 the receiving vessel (the truck or railcar). Vapor balancing requires a pipe or hose connected
13 between the storage vessel and the receiving vessel prior to transfer. Bottom loading and
14 submerged filling are additional best management practices used to reduce emissions from
15 hydrocarbon liquid transfers.

16 Proposed Rule Requirements for Hydrocarbon Liquid Transfers

17 Section 20.2.50.120 requires owners or operators to control VOC emissions by at least
18 98% via vapor balance, vapor recovery, or a control device.

19 If using vapor balance, the rule at 20.2.50.120.B(2)(a) through (e) imposes the following
20 requirements: owners and operators must load displaced vapor back to the vessel being emptied
21 via pipe or hose connected before the start of the transfer operation; transfer cannot begin until
22 the vapor collection and return systems are properly connected; connector pipes, hoses, couplers,
23 valves and pressure relief devices must be free of leaks; liquid and vapor line connections must

1 be checked for proper connection prior to commencing the transfer operation; and the transfer
2 equipment must be operated at a pressure that is less than the pressure relief valve setting of the
3 receiving vehicle or vessel.

4 Bottom loading or submerged filling are required; splash loading is not an acceptable
5 method of transfer under the rule.

6 For all transfer operations, hose and pipe connections must be supported on drip trays to
7 collect any leaks, and the materials collected must be returned to the process or properly
8 disposed of. Leaks must be cleaned and disposed of in a manner that minimizes emissions to the
9 atmosphere, and the material collected must be returned to the process or properly disposed of.

10 Owners and operators employing a control device to comply with the emission standards
11 of Section 20.2.50.120 are required to comply with the control device requirements in Section
12 20.2.50.115.

13 Owners or operators are required to visually inspect the transfer equipment during a
14 transfer operation to ensure that components are not leaking. If leaks are discovered, they must
15 be repaired prior to the next transfer operation. Operations employing a control device must
16 follow the manufacturer's recommend operation and maintenance procedures. An owner or
17 operator using vapor balance, vapor recovery, or a control device to minimize VOC emissions
18 must comply with the monitoring requirements contained in Section 20.2.50.115. All owners and
19 operators shall comply with the general monitoring requirements in Section 20.2.50.112.

20 Owners or operators of a storage vessel subject to Section 20.2.50.120 must maintain a
21 record of the storage vessel and, if using a control device, records of the type, make and model.
22 The owner or operator must also maintain a record of all required inspections. Records must also
23 be maintained of the annual total hydrocarbon liquid transferred and annual VOC emissions from

1 each site. On an annual basis, the owner or operator is required to create a company-wide record
2 summarizing the total annual hydrocarbon liquid transferred and the total annual calculated VOC
3 emissions.

4 Owners and operators must also comply with the general recordkeeping and reporting
5 requirements in Section 20.2.50.112.

6 Basis for Proposed Rule Requirements

7 The proposed control and operational requirements are based on requirements in
8 Colorado's Reg. 7, Section II.C.5 (NMED Exhibit 39); Pennsylvania GP-5 and GP-5A (NMED
9 Exhibits 37 and 38); Utah's Rule R307-504 – Oil and Gas Industry: Tank Truck Loading,
10 (NMED Exhibit 83); and Wyoming's presumptive BACT for oil and gas truck loading
11 operations, found in the Wyoming Permitting Guidance (NMED Exhibit 40). As described
12 below, these other states require various best management practices and/or the use of control
13 devices such as enclosed combustors to control emissions from hydrocarbon liquid transfers.

14 The proposed emission standard in 20.2.50.120.B(1) requiring all hydrocarbon liquid
15 transfer operations to use vapor balance, vapor recovery, or a control device to control VOC
16 emissions by at least ninety-eight percent is based on the following:

- 17 1) Colorado Reg. 7, Section II.C.5.a, which requires control of loadout emissions from
18 controlled storage tanks to transport vehicles by using (a) submerged fill and (b) a
19 vapor collection and return system and/or air pollution control equipment;
- 20 2) Pennsylvania GP-5A, Section F, which requires use of a vapor balancing system when
21 removing liquids from the storage vessel;
- 22 3) Utah's Rule R307-504-4, which requires using a vapor capture line connected to a
23 control of process with 95% destruction efficiency; and

1 4) Wyoming's Permitting Guidance, Chapter 6, Sec. 2, which requires a vapor capture
2 line with a collection efficiency of 70% connected to a control device with a
3 destruction efficiency of 98%.

4 The proposed standard in 20.2.50.120.B(2)(a) through (e) for owners and operators using
5 the vapor balance option (see proposed requirements section above) is based on Colorado Reg. 7,
6 part D, Section II.C.5.a.(iii)(A)-(E). The proposed emission standard in 20.2.50.120.B(3)
7 requiring liquid transfers to use bottom loading or submerged filling is similar to Utah's Rule
8 R307-504-4(1). The proposed emission standards in 20.2.50.120.B(4) and (5) requiring
9 connector pipes and couplers be maintained in a leak-free condition and connections be
10 supported on drip trays during transfer operations is similar to Colorado Reg. 7, part D, Section
11 II.C.5.a.(iii)(E). The emission standards in 20.2.50.120.B(6) requiring liquid leaks be cleaned
12 and disposed in a manner that minimizes emissions to the atmosphere is based on good
13 engineering practices.

14 Because vapor balancing during transfers from storage vessels to transport vessels returns
15 all vapors displaced from the tanker truck or railcar back into the storage vessel, and because all
16 emissions from storage vessels with a PTE equal to or greater than 2 tpy of VOC are required to
17 be controlled, the emissions attributed to vapor balancing are controlled at the storage tank by the
18 requirements for storage vessels in Section 20.2.50.123. During liquid transfers from trucks and
19 railcars to storage vessels, the vapor balancing requirements would require transfer of displaced
20 vapors back to the trucks/railcars up to the pressure relief limits of these vessels, at which point
21 excess emissions would be controlled by the storage tank control devices. Thus, any excess
22 emissions generated during liquid transfers are controlled.

1 Estimated Emissions Reductions

2 Based on the NMED Equipment Data, ERG identified 684 active hydrocarbon liquid
3 transfer operations in the Subject Counties with annual allowable VOC emission limits that
4 allow for emissions reductions estimates. These 684 operations are located at 637 unique
5 facilities. The total allowable VOC emissions from these 684 operations are 4,911 tpy. Of these
6 684 operations, there are 537 without controls. To estimate reductions, a 98% control efficiency
7 was applied to these operations, resulting in total emissions reductions of 4,263 tpy of VOC for
8 an overall reduction of 86.8%. *See NMED Exhibit 84 – Transfers Reductions and Costs*
9 Spreadsheet.

10 Estimated Costs

11 Based on the NMED Equipment Data, ERG identified 537 affected hydrocarbon liquid
12 transfer operations in the Subject Counties that require additional controls. For purposes of
13 estimating costs, ERG assumed that each unique facility with operations requiring control would
14 only require one control device that would be used to control emissions from all affected
15 operations at that facility. There are 493 such facilities. As mentioned previously, many facilities
16 use a common control device to control emissions from both storage tanks and liquid transfer
17 operations. Therefore, ERG assumed that the only facilities that would require controls for
18 purposes of complying with the hydrocarbon liquid transfer operations requirements are those
19 facilities without a current control device and that would not already be required to install a new
20 control device under the storage tank provisions in 20.2.50.123 NMAC. There are 130 such
21 facilities, and the total estimated annualized costs of installing controls at these facilities is
22 \$2,283,886. These costs result in an overall cost effectiveness of \$536/ton of VOC controlled.
23 The annualized cost includes capital and installation costs, as well as operation and maintenance

costs for installing combustors at the 130 affected facilities. The capital and annual costs per combustor are based on cost figures in the EPA CTG. *See* NMED Exhibit 34 at Table 4-5 – *Total Capital Investment and Total Annual Costs of a Combustor*. Costs were updated to reflect 2019 costs using the CEPCI of 584.6 for 2012\$ and 607.5 for 2019\$. The 2019 to 2012 cost ratio is therefore estimated as:

$$607.5/584.6 = 1.04$$

A detailed breakdown of costs for hydrocarbon liquids transfers is provided in the Transfers Reductions and Costs Spreadsheet (NMED Exhibit 84).

Section 20.2.50.121 – Pig Launching and Receiving

Applicability

Section 20.2.50.121 applies to owners and operators of pipeline pig launching and receiving operations located within or outside of the property boundary of well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and natural gas compressor stations.

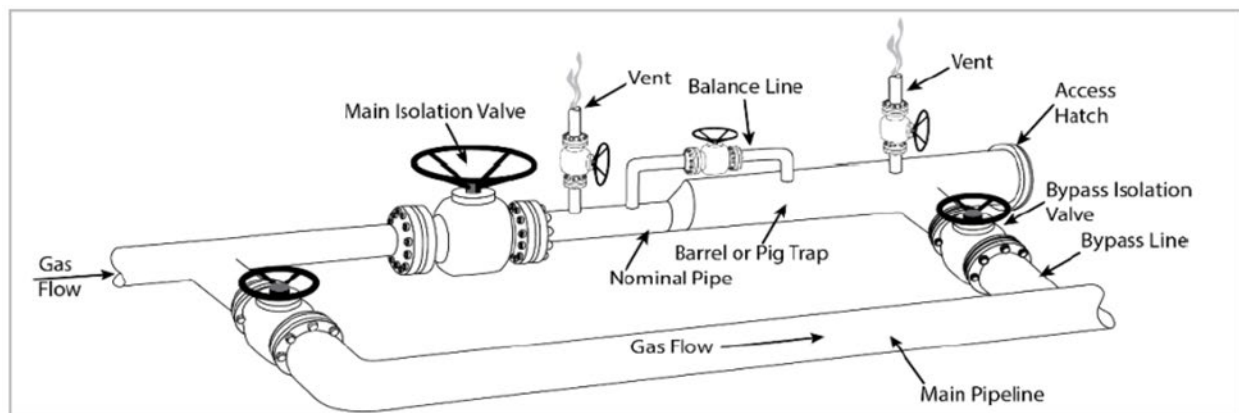
Description of Process

Natural gas passing through gathering pipelines contains VOCs, as well as other impurities such as water and carbon dioxide. As this gas passes through the pipeline system, any change in temperature or pressure may result in development of natural gas condensates in a liquid phase in the pipeline. These natural gas condensates can accumulate in low elevation segments of the gathering pipelines, impeding the flow of natural gas. To maintain gas flow and operational integrity of these pipelines, operators insert a device called a “pig” into the pipeline which is swept along the pipeline by the pressure of the existing gas flow. Condensate and any other solid or liquid materials that have formed in the pipeline are pushed along in front of the

1 pig until it reaches a “receiver,” at which point the pig is isolated in an offshoot pipeline segment
2 and any condensates and liquids are drained out of the pipeline. The pig is then reinserted and
3 swept along the next segment of pipeline. Pigs may also be used to create physical separation
4 between different fluids flowing through the pipeline, for cleaning the internal surfaces of the
5 pipelines, inspection of the condition of pipeline walls, and recording information relating to
6 pipelines (e.g., size, location).

7 Emissions to the atmosphere may occur at both the pig launcher and receiver when the
8 pipeline is opened to insert or extract the pig. Emissions from pigging operations depend on
9 factors such as the launcher or receiver volume, pipeline pressure, the amount of liquid trapped
10 in the pig receiver barrel prior to depressurization, frequency of pigging, and gas composition.

11 A conventional pig receiver is shown in Figure 1.¹⁹ Pig launchers are very similar in
12 design.



14 **Figure 1 Conventional Pig Receiver**

¹⁹ “EPA Observes Air Emissions from Natural Gas Gathering Operations in Violation of the Clean Air Act”. Publication no. EPA 325-F-19-001. September 2019.

1 Control Options for Pig Launching and Receiving

2 Emissions from pigging operations may be controlled through process modifications,
3 through the use of add-on controls such as a flare, enclosed combustor or thermal oxidizer, or by
4 using a vapor recovery unit (VRU). Process modifications identified by EPA to minimize
5 emissions include:

- 6 • *Installing pig ball valves* - Pig ball valves are designed with a smaller sized barrel (or
7 chamber) that launches and receives the pig which reduces the volume of gas that may be
8 vented when the pig launcher or receiver is opened.
- 9 • *Receiver Barrel Design: Pig Ramps* - A pig ramp is a device that minimizes the
10 accumulation of condensate in the receiver by directing the movement of the pig and
11 liquid in the barrel to direct the flow of liquid into a bypass line. As part of a recent EPA
12 settlement with midstream operator MarkWest, pig ramps were installed at hundreds of
13 barrels in its wet gas midstream pipeline systems. *See* NMED Exhibit 85 – Consent
14 Decree – *U.S. v. MarkWest Liberty Midstream & Resources, LLC*, No. 2:18-cv-00520-
15 LPL (W.D. Penn., April 24, 2018) (“MarkWest Consent Decree”).
- 16 • *Route High Pressure Systems to Lower Pressure Lines (Install Jumper Lines)* –
17 Emissions from the opening of pig launchers and receivers can be reduced by routing
18 high pressure gases in the unopened barrel to a lower pressure system before venting the
19 remaining gases to the atmosphere or to control equipment.
- 20 • *Barrel Pump-down Systems* - Small fixed or portable compressors are used to pump gases
21 in the receiver or a launcher barrel back into the main pipeline prior to opening the barrel.
22 Barrel pump-down systems can recover greater than 99% of the depressurization vapors
23 from pig launchers and receivers.

- *Enhanced Liquid Containment* - Liquids remaining in a receiver barrel after depressurization can be emptied into a container fitted with an impermeable material to reduce evaporative emissions from the liquids emptied from the barrel.

Additional technical details on pig launching and receiving emissions and mitigation strategies may be found in the MarkWest Consent Decree.

Proposed Rule Requirements for Pig Launching and Receiving

Section 20.2.50.121 requires affected facilities to comply with best management practices and emission limits. Owners and operators of pigging operations with a PTE equal to or greater than 1.0 tons VOC per year are required to capture and reduce VOC emissions by 98%. In addition, owners and operators must employ a suite of best management practices and equipment modifications during pigging operations to prevent or reduce emissions.

Basis for Proposed Requirements

The proposed requirements for pigging operations are based on Pennsylvania GP-5 and GP-5A, and Ohio's General Permit 21.1 for Title V and non-Title V pigging operations ("Ohio General Permits").²⁰ See NMED Exhibits 37, 38, and 86, respectively.

Pennsylvania GP-5A is applicable to sources located at unconventional natural gas well site operations and remote pigging stations, and Pennsylvania GP-5 is applicable to sources located at natural gas compression stations, processing plants, and transmission stations. The best management practices required in the Pennsylvania General Permits are required for all pigging operations. The same best management practices are also recommended in EPA's PRO Fact Sheet No. 505, *Recover Gas from Pipeline Pigging Operations* ("EPA Fact Sheet No. 505") (NMED Exhibit 87),²¹ and a September 2019 EPA Enforcement Alert, EPA Publication No.

²⁰ Available at: https://www.epa.ohio.gov/dapc/genpermit/ngcs/GP_211

²¹ Available at: <https://www.epa.gov/sites/production/files/2016-06/documents/pigging.pdf>

1 325-F-19-001 (NMED Exhibit 88).²² The VOC emissions limit in Pennsylvania GP-5 and GP-
2 5A apply to pigging operations that still have emissions equal to or greater than 2.7 tpy after
3 employing best management practices. The Pennsylvania emission limit requires the owner or
4 operator to control VOC emissions from all pigging operations by at least 95% with a control
5 device. *See* NMED Exhibit 37 and 38 at p. 24.

6 Ohio has similar emission limits for pigging operations in its General Permits. Both
7 general permits limit VOC emissions from one discrete pig launcher or receiver to less than 0.27
8 tons per month, averaged over a rolling 12-month period (equivalent to less than 3.24 tpy). The
9 Ohio General Permits require use of an add-on control device to control emissions if needed to
10 comply with the VOC emission limitations. *See* NMED Exhibit 86 at p. 4.

11 Estimated Emissions Reductions

12 Based on the NMED Equipment Data, ERG identified 10 facilities with pigging
13 operations. However, this is not a complete inventory of pigging operations because they are
14 most often located within other facilities and are not identified separately in NMED's permitting
15 and facility databases. Further, pigging operations are also not quantified separately in the data
16 from EPA's Greenhouse Gas Reporting Program for Petroleum and Natural Gas Systems, 40
17 CFR § 98, Subpart W.

18 Of the 10 facilities determined from NMED data, four facilities have five pigging
19 operations with allowable VOC emissions equal to or greater than 1 tpy VOC each. Based on the
20 applicability threshold of 1 tpy VOC, these operations would be required to implement
21 reductions of 98% pursuant to 20.2.50.121.B(1). Total allowable VOC emissions from these five
22 operations are 24.1 tpy, so the total reductions would be 23.6 tpy VOC based on the 98% control

²² Available at: <https://www.epa.gov/sites/default/files/2019-09/documents/naturalgasgatheringoperationinviolationcaa-enforcementalert0919.pdf>

1 requirement. Total emissions from the pigging operations with emissions below the 1 tpy VOC
2 98% control applicability threshold are 1.6 tpy VOC, resulting in an overall control efficiency of
3 92%.

4 Estimated Costs

5 EPA Fact Sheet No. 505 provides an estimate of the costs and benefits of capturing
6 liquids and gas from pigging operations. *See* NMED Exhibit 87. According to that document,
7 best management practices for recovery of liquids and gas would require separating pigged
8 liquids from the gas, storing the liquids temporarily at gathering system pressure, and then
9 sending them to a low-pressure storage tank. These liquids (recovered at pipeline pressure)
10 would flash and vent light hydrocarbon gases from the storage tanks. The flash emissions would
11 be recovered by installing a dedicated vapor recovery system on the vessel where the liquids are
12 depressurized. The recovered gas would then be sent to the sales line. This process would reduce
13 emissions and add more gas to the sales line. The EPA 505 Fact Sheet states:

14 The required equipment to be installed includes an electric or a gas engine driven vapor
15 recovery compressor. A liquid/vapor flash vessel and low-pressure liquid pump may also
16 be required depending on system design and/or ambient temperature and pressure. It is
17 assumed that a pig launcher and receiver on gathering lines, vapor/liquid separation and
18 pressurized liquid storage vessels, and low-pressure liquid storage tanks would already be
19 present on site.

20 *Id.* at p. 1-2.

21 The cost estimates presented in EPA Fact Sheet No. 505 would be appropriate for
22 launching and receiving stations located adjacent to processing plants or pipeline compressor
23 stations that may already have the equipment needed for recovery on-site. In a presentation titled
24 “Vapor Recovery and Gathering Pipeline Pigging” at the July 2008 Producers and Processors
25 Technology Transfer Workshop in Midland, Texas, EPA provided an example from one Natural
26 Gas STAR Program partner that purchased equipment and implemented this process. *See* NMED

Exhibit 89, Slide 35. This company installed a dedicated vapor recovery unit with an electric compressor at an installed cost of \$24,000 and an annual operating cost of \$40,000 (mostly for electricity). However, based on the value of the condensate recovered, the payback period for the same installation was estimated to be approximately 4 months.

Alternatively, companies may choose to use a temporary skid-mounted flare to meet the control standard for remote pigging operations or pigging operations where the existing infrastructure does not support product recovery. EPA Natural Gas STAR Program's PRO Fact Sheet No. 904, *Install Flares* (2011), provided costs to install and operate a flare at a remote site. See NMED Exhibit 90. The estimated implementation cost of a skid-mounted flare is \$21,000 and the operating costs per year are \$3,000, plus any fuel needed for a pilot light. If the flare were portable, it could be moved to sites on an as-needed basis, with additional cost for transport and set-up added for each pigging operation.

Section 20.2.50.122 – Pneumatic Controllers and Pumps

Applicability

The requirements of Section 20.2.50.122 apply to natural gas-driven pneumatic controllers and pumps, as defined in Section 20.2.50.7, that are located at well sites, tank batteries, gathering and boosting stations, natural gas processing plants, and natural gas compressor stations.

Description of Equipment and Process

Pneumatic controllers are process control devices used throughout the oil and natural gas industry as part of the instrumentation to control the position of valves. Natural gas-powered pneumatic controllers use natural gas as motive force to operate valves that regulate safety shut-down, position, fluid level, pressure, temperature and flow rate in oil and natural gas production

1 and processing. *See* NMED Exhibit 34 (EPA CTG). Pneumatic controllers may also be powered
2 by compressed air instead of natural gas.

3 Pneumatic controllers are used to control multiple processes based on a sensed process
4 parameter, such as liquid level in a tank or oil-water separator. Pneumatic controllers can be used
5 as emergency shutoff devices, to regulate flow or liquid levels, or as temperature and pressure
6 regulators. An example of the function of a pneumatic controller would be to control the liquid
7 level in a separator. When the liquid level reaches a high set-point in the separator based on the
8 setting of a level gauge, the associated pneumatic controller sends a signal to open the control
9 valve between the separator and the tank. For an emitting pneumatic controller, this signal would
10 consist of pressurized pneumatic gas turning the valve from the “closed” to the “open” position.
11 When the level in the separator reaches a low level, the pneumatic controller sends a signal to the
12 control valves to close and to stop flow from the separator to the tank. *See* NMED Exhibit 10
13 (MAP Technical Report).

14 VOC and methane emissions occur from natural gas-powered pneumatic controllers
15 when the pressurized gas is directed to atmosphere after the control action is performed. *See*
16 NMED Exhibit 34 (EPA CTG).

17 Pneumatic pumps are used to inject chemicals into the wellbore, to circulate glycol in
18 cold climates, and to move liquids from one place to another (sump pumps). Pneumatic pumps
19 range from chemical injection pumps which may inject a few tablespoons of corrosion inhibitor
20 to a well bore, to large diaphragm pumps which move thousands of gallons of product per hour
21 from one tank to another, to pump water out of containment areas after wet weather, or for heat
22 trace to protect pipes from freezing in cold weather. *See* NMED Exhibit 34 (EPA CTG); NMED
23 Exhibit 10 (MAP Technical Report).

1 VOC and methane emissions occur from pneumatic pumps when the pressurized natural
2 gas used to drive the pumping action is released to atmosphere after being used for the pumping
3 action. The quantity of VOCs emitted is dependent on the type of pump employed and the
4 concentration of VOCs in the gas stream. *See* NMED Exhibit 10 (MAP Technical Report).
5 Depending on their intended use, natural gas-driven pneumatic controllers and pumps are
6 available in a variety of designs, but may be characterized by their bleed rate, which is a measure
7 of how much natural gas is used to operate the pneumatic controller or pump, and therefore the
8 emissions from the pneumatic controller or pump.

9 Continuous bleed pneumatic controllers have a continuous supply of natural gas to the
10 process controller (e.g., liquid level control, temperature control, or pressure control) and emit
11 or “bleed” natural gas continuously while the natural gas pressure in the controller is balanced
12 against the process condition (e.g., liquid level, temperature, and pressure), and compared with
13 the associated process set-point. When the process condition rises or falls above or below that set
14 point, the pneumatic controller responds to return the process to that predetermined set point.
15 Continuous bleed controllers may either be low bleed (with a bleed or emissions rate less than or
16 equal to 6 standard cubic feet per hour (scfh), or high bleed (with a bleed or emissions rate
17 greater than 6 scfh).

18 Intermittent pneumatic controllers do not vent continuously, but instead release gas only
19 when they open or close a valve, or as they throttle (i.e., adjust) gas flow. The bleed rate from
20 these controllers depends on the amount of gas vented per actuation (i.e., each opening or closing
21 of a valve or adjustment of gas flow) and the frequency of actuation.

22 Zero bleed pneumatic controllers do not bleed natural gas at all. They are self-contained
23 units that release gas to a downstream pipeline. *See* NMED Exhibit 91 – EPA Office of Air

1 Quality Planning and Standards, *Oil and Natural Gas Sector Pneumatic Devices: Report for Oil*
2 *and Natural Gas Sector Pneumatic Devices Review Panel as part of the President's Climate*
3 *Action Plan: a Strategy to Reduce Methane Emissions* (April 2014) ("EPA 2014 O&G
4 Pneumatic Devices Report").

5 Control Options for Pneumatic Controllers and Pumps

6 There are several ways to reduce emissions from pneumatic controllers, including
7 replacing high bleed controllers with low bleed or zero bleed models, using instrument air rather
8 than natural gas to drive controllers, and using non-gas-driven controllers such as mechanical or
9 electric controllers, including solar-powered controllers. Regular maintenance and proper
10 adjustment of pneumatic controllers can also be used to minimize emissions by repairing leaks
11 and optimizing the amount of gas needed to operate the device. Options for reducing emissions
12 from pneumatic pumps include using instrument air rather than natural gas to drive pumps, using
13 non-gas-driven pumps, such as electric pumps, or routing emissions to a control device or
14 process. See NMED Exhibit 92 – EPA Office of Air and Radiation, *Options for Reducing*
15 *Methane Emissions from Pneumatic Devices in the Natural Gas Industry* (October 2006).

16 Proposed Rule Requirements for Pneumatic Controllers and Pumps

17 All new natural gas-driven pumps are required to comply with the emission standards of
18 20.2.50.122 upon startup. Owners or operators of existing natural gas-driven pneumatic pumps
19 must comply with the emission standards in Section 20.2.50.122 within three years of the
20 effective date of Part 50.

21 The schedules and targets for replacing existing natural gas-driven pneumatic controllers
22 with non-emitting controllers are contained in Table 1: Well Sites, Tank Batteries, Gathering and
23 Boosting Stations, and Table 2: Natural Gas Compressor Stations and Gas Processing Plants.

1 The target is based on the number of pneumatic controllers at all of the owner or operator's
2 affected facilities that commenced construction before the effective date of Part 50. The total
3 controller count must include all emitting pneumatic controllers and all non-emitting pneumatic
4 controllers, except pneumatic controllers that are necessary for a safety or process purpose that
5 cannot otherwise be met without emitting natural gas.

6 New pneumatic controllers are required to have an emission rate of zero, as are existing
7 pneumatic controllers with access to commercial line electrical power. Pneumatic controllers
8 with a bleed rate exceeding six standard cubic feet per hour are allowed if the owner or operator
9 has demonstrated to the satisfaction of the Department that a higher bleed rate is required based
10 on functional needs. Natural gas-driven pumps located at natural gas processing plants must have
11 an emission rate of zero. Natural gas-driven pumps located at well sites, tank batteries, gathering
12 and boosting stations, or natural gas compressor stations with access to commercial power must
13 have an emission rate of zero.

14 Owners and operators of pneumatic pumps at well sites, tank batteries, gathering and
15 boosting stations, or natural gas compressor stations without access to commercial line electrical
16 power are required to reduce VOC emissions from this equipment by 95 percent if it is
17 technically feasible to route those emissions to a control device, fuel cell, or process. If an
18 existing on-site control device is not capable of achieving a 95 percent reduction of VOC
19 emissions, and it is not technically feasible to route pneumatic pump emissions to a fuel cell or
20 process, the owner or operator must route the emissions to the existing control device.

21 Owners and operators of pneumatic controllers or pumps must install an EMT on each
22 device in accordance with Section 20.2.50.112.

1 Section 20.2.50.122 contains monitoring, recordkeeping, and reporting requirements that
2 ensure the owner or operator is properly operating and maintaining the affected pumps and
3 controllers in a manner that meets the emissions reduction requirements in the rule. Pneumatic
4 controllers or pumps with a natural gas bleed rate equal to zero are not subject to the monitoring
5 or recordkeeping requirements of Section 20.2.50.122. The owner or operator of any controller
6 subject to the deadlines in this section must monitor the compliance status of each controller at
7 each facility and must develop and record the schedule and compliance status for each controller
8 so that it meets the compliance deadlines.

9 The monitoring requirements for controllers or pumps with a gas bleed rate greater than
10 zero include monthly AVO, mechanical inspections, and maintenance to ensure VOC emissions
11 are minimized. The owner or operator must maintain an electronic record for each affected
12 controller or pump that contains the ID number, controller type, design continuous bleed rate for
13 continuous controllers, bleed volume per bleed for intermittent controllers, each controller's
14 design annual bleed rate, inspection dates, name of personnel conducting the inspection, AVO
15 inspection result, AVO level discrepancy in continuous or intermittent bleed rate, maintenance
16 date and activity, and a record of the justification for use of a controller with a bleed rate greater
17 than six scfh.

18 Owners and operators are required to maintain a total count of all emitting and non-
19 emitting pneumatic controllers at affected facilities that commenced operation prior to the
20 effective date of Part 50 and maintain a total count of units necessary for safety or process
21 purposes that cannot be met without emitting VOC.

22 Electronic records must be maintained for natural gas-driven pneumatic pumps and the
23 associated pump numbers that have emission rates greater than zero. The record must include the

1 dates of operation for any pump operating less than 90 days per calendar year; any control device
2 designed to achieve at least 95% emission reduction, including an evaluation or the manufacturer
3 specifications indicating percent reduction the control device is designed to achieve; and
4 documents of engineering assessments and certifications from a qualified professional engineer
5 stating that routing pneumatic pump emissions to a control device, fuel cell, or process is
6 technically infeasible.

7 The owner or operator must also meet the monitoring, recordkeeping, and reporting
8 requirements in Section 20.2.50.112.

9 Basis for Proposed Rule Requirements

10 The proposed rule is based on similar rules for new and existing pneumatic controllers
11 and pneumatic pumps in Colorado Reg. 7, Sections I.K, III.C, and III.D. *See* NMED Exhibit 39.

12 The emission standard in 20.2.50.122.B(4)(a) requiring all new pneumatic controllers to
13 have an emission rate of zero is based on Colorado Reg 7, Section III.C.1-3. The proposed
14 standard is stricter than the Colorado standard in that it requires all new pneumatic controllers to
15 have a bleed rate of zero. Both rules allow for exceptions where a pneumatic controller with a
16 non-zero bleed rate is required for safety and/or process considerations.

17 The emission standard in 20.2.50.122.B(4)(b) requiring all existing pneumatic controllers
18 with access to electrical power to have an emission rate of zero is based on Colorado Reg. 7,
19 Section III.C.3.a.(i). Both rules allow for exceptions where this is not technically feasible.

20 The emission standard in 20.2.50.122.B(4)(c) requiring that a percentage of a company's
21 total number of existing pneumatic controllers be replaced with non-emitting controllers by a
22 certain date is based on a similar provision in Colorado Reg. 7, Section III.C.4. The requirement
23 in 20.2.50.122.B(3) and (4)(c) that a company's "fleet" of pneumatic controllers must be

1 replaced over time with non-emitting or low-emitting controllers is based on the fact that many
2 high bleed, low bleed, and intermittent bleed devices can be replaced with either non-emitting
3 devices or lower-emitting devices, while allowing for continued use of those non-zero emitting
4 controllers that cannot be replaced for safety and/or process considerations. This approach
5 provides owners and operators flexibility to assess their total operations and reduce emissions
6 from pneumatic controllers in ways they deem most cost-effective.

7 In 2017, the Colorado Air Quality Control Commission (“COAQCC”) established the
8 Statewide Hydrocarbon Emission Reduction (“SHER”) team and the Pneumatic Controller Task
9 Force (“PCTF”). The SHER team and the PCTF worked for two years and produced a report on
10 pneumatic controllers in June 2020. *See* NMED Exhibit 93, *PCTF Report to the Air Quality*
11 *Control Commission: Pneumatic Controller Field Study and Recommendations* (June 1, 2020)
12 (“2020 PCTF Report”). In 2019, the Colorado Legislature passed Senate Bill 19-181 directing
13 the COAQCC to consider requirements to reduce emissions from pneumatic devices. On
14 February 18, 2021, COAQCC amended Colorado Reg. 7, Section III (“2021 Reg. 7
15 Amendments”) to require more stringent standards to reduce VOC emissions from pneumatic
16 controllers. *See* NMED Exhibit 39 (Colorado Reg. 7, Section III). The February 2021
17 rulemaking was informed by the 2020 PCTF Report.

18 Among other things, the 2021 Reg. 7 Amendments require the use of non-emitting
19 controllers at new well production facilities and new natural gas compressor stations. *See*
20 Colorado Reg. 7, Section III.C.4.a. The 2021 Reg. 7 Amendments also require companies to
21 develop and submit company-wide plans to convert most of their pneumatic controllers at
22 existing facilities to non-emitting controllers over a two-year period. Colorado Reg. 7, Section
23 III.C.4.b. The percentage of controllers that must be converted is based on the historic percentage

1 of non-emitting controllers in that company, determined by the company as part of developing
2 their plan. Companies with a lower percentage of non-emitting controllers will have to meet a
3 lower final percentage of non-emitting controllers, but will need to achieve a higher percentage
4 of additional controllers converted to non-emitting. Conversely, companies with a higher
5 percentage of non-emitting controllers will have to meet a higher final percentage of non-
6 emitting controllers but will need to achieve a lower percentage of additional controllers
7 converted to non-emitting. Section 20.2.50.122 proposes similar requirements for controllers at
8 new and existing facilities.

9 The emission standard proposed in 20.2.50.122.B(4)(d), which allows use of pneumatic
10 controllers with a bleed rate greater than 6 scfm in operations where the controller's use is
11 "required based on functional needs, including response time, safety, and positive actuation," is
12 similar to the exceptions allowed in NSPS Subpart OOOOa, 40 CFR §6 0.5390a(a), and
13 Colorado Reg. 7, Section III.C.3.a.(ii).

14 The emission standard proposed in 20.2.50.122.B(5)(a), which requires all new and
15 existing pneumatic pumps located at natural gas processing plants to have an emission rate of
16 zero, is similar to the requirement in Colorado Reg. 7, Section I.K.1.

17 The emission standard proposed in 20.2.50.122.B(5)(b), which requires all new and
18 existing pneumatic pumps located at a well sites, tank batteries, gathering and boosting stations,
19 or natural gas compressor stations with access to commercial line electrical power to have an
20 emission rate of zero, is similar to the requirement in Colorado Reg. 7, Section I.K.1. This
21 requirement is also based on an assumption that, at sites with access to electrical power, it is
22 feasible to replace emitting pumps with non-emitting pumps. This assumption is supported by
23 the fact that data from EPA's Greenhouse Gas Reporting Program ("GHGRP") for Petroleum

1 and Natural Gas Systems (40 CFR 98, subpart W) indicate that natural gas processing plants,
2 which all have access to electrical power, already have 100-percent non-emitting controllers and
3 pumps.

4 The emission standard proposed in 20.2.50.122.B(5)(c), which requires all new and
5 existing pneumatic pumps located at a well sites, tank batteries, gathering and boosting stations,
6 or natural gas compressor stations without access to commercial line electrical power to route
7 emissions to a control device, fuel cell, or process if it is technically feasible, is similar to the
8 requirement in CO Reg 7, Sec.I.K.2. Both rules allow exceptions if the requirement is not
9 technically feasible.

10 The proposed requirement in 20.2.50.122.B(6) that all pneumatic controllers and pumps
11 be tagged with an EMT is similar to the requirement in Colorado Reg 7, Section III.D.2.a, which
12 requires pneumatic controllers located at a natural gas processing plant with a natural gas bleed
13 rate greater than zero must be physically tagged by the owner or operator identifying it with a
14 unique pneumatic controller number that is assigned and maintained by the owner or operator.

15 Estimated VOC Emissions Reductions

16 Data for the number of pneumatic devices at oil and gas operations in New Mexico was
17 derived from well data providing the number and age of wells, permit data providing the number
18 of other types of (non-well) facilities, and technical papers estimating the number of pneumatic
19 controllers and pumps found at each type of facility and their average VOC emission rates.

20 Although NMED does not have an equipment inventory listing pneumatic controllers or pumps,
21 estimates for the number of pneumatic devices at well sites, tank batteries, gathering and
22 boosting stations, natural gas processing plants, and compression/transmission sites were derived

1 by combining data on the number of each type of site in New Mexico with EPA data on the
2 number of controllers and pumps found at each type of site in the Permian and San Juan Basins.

3 Well count data came from the Petroleum Recovery Research Center (“PRRC”), which is
4 an organization that provides up to date information on oil and gas production data for New
5 Mexico.²³ Oil and gas production data on the PRRC website has been provided primarily by the
6 New Mexico Oil Conservation Division and is updated on a monthly basis. The data downloaded
7 from the PRRC site represents all producing oil and gas wells in the Subject Counties for the
8 year 2020. See NMED Exhibit 94 – 2020 Producing Wells Spreadsheet. Although NMED has
9 permit data for some wells and storage tanks, these data were not used in the analysis of
10 pneumatic controllers and pumps as it was deemed incomplete because many wells and tanks do
11 not require a permit from NMED. Tank batteries were combined with well sites and both were
12 treated as one site for pneumatic device emission purposes, as these facilities are typically found
13 together at the upstream end of the oil and gas production operations. Facility count data for
14 gathering and boosting stations, natural gas processing plants, and transmission/compression
15 stations came from the NMED Equipment Data. NMED permit data categorizes both
16 gathering/boosting stations and transmission/compression sites as “Compressor Stations,” so
17 these two categories were disaggregated by assuming that a “Compressor Station” with a Title V
18 permit is a transmission/compression station and all other “Compressor Stations” are gathering
19 and boosting stations. This assumption was based on the fact that pipeline
20 transmission/compression stations typically have several operating compressor engines or
21 turbines onsite, and therefore are typically major sources of NOx which would require a Title V
22 permit.

²³ Available at: http://gotech.nmt.edu/gotech/Petroleum_Data/allwells.aspx

1 Based on the NM well count and NMED permit data, there are 27,489 wellheads in the
2 Permian Basin and 20,448 wellheads in the San Juan Basin; 570 gathering/boosting stations in
3 the Permian Basin and 345 gathering/boosting stations in the San Juan Basin; 40 natural gas
4 processing plants in the Permian Basin and 8 natural gas processing plants in the San Juan Basin;
5 and 29 transmission/compression stations in the Permian Basin and 39 transmission/compression
6 stations in the San Juan Basin. See NMED Exhibit 95 – Pneumatics Reductions and Costs
7 Spreadsheet, “Facility Data” tab.

8 The number of devices per site for low-bleed, intermittent-bleed, and high bleed
9 pneumatic controllers, as well as pneumatic pumps at each of these types of sites, was
10 determined using EPA’s GHGRP, Subpart W data for 2019. These counts are based on producer-
11 reported data for the Permian and San Juan Basins. See NMED Exhibit 96 – NM Pneumatics
12 Data Subpart W Spreadsheet, “Facility Data” tab. Based on data in Table 2-2 of the EPA 2014
13 O&G Pneumatic Devices Report, ERG assumed that all controllers and pumps at natural gas
14 processing plants are non-emitting. See NMED Exhibit 91.

15 ERG also assumed that for well sites/tank batteries, gathering/boosting stations, and
16 transmission/compression stations, 20% of all pneumatic devices are already non-emitting. This
17 assumption was made to account for the fact that some non-emitting devices have already been
18 put into service, and to avoid overestimating emission reductions. However, the actual frequency
19 at which non-emitting controllers are used in New Mexico is not known. EPA indicated in the
20 EPA 2014 Pneumatic Devices Report that it has not obtained any information on the prevalence
21 of “zero-bleed” controllers in the field. See NMED Exhibit 91 at p. 41. The 2020 PCTF Report
22 indicated that non-emitting controllers were not included in the scope of the 2018 PCTF field
23 study of controllers in the Denver-Julesburg (DJ) Basin because the intent of the study was only

1 to examine emissions associated with natural gas-driven controllers. *See* NMED Exhibit 93 at p.
2 6.

3 The uncontrolled emission rates (also referred to as “emission factors”) for low-bleed,
4 intermittent-bleed, and high-bleed controllers, as well as pneumatic pumps, were based on four
5 EPA sources. The emission rate of intermittent bleed devices and the data for VOC emissions
6 from pneumatic devices at gathering and boosting stations comes from Subpart W of 40 CFR
7 Part 98, Table W-1A – *Default Whole Gas Emission Factors for Onshore Petroleum and Natural*
8 *Gas Production Facilities and Onshore Petroleum and Natural Gas Gathering and Boosting*
9 *Facilities*. *See* NMED Exhibit 97 – 80 Fed. Reg. 64262, *Greenhouse Gas Reporting Rule: 2015*
10 *Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems* (October
11 22, 2015). The data for VOC emission rates from low-bleed and high-bleed controllers in the
12 production segment comes from Table 6-2 of the EPA CTG (NMED Exhibit 34). The data for
13 the VOC emission rate from low-bleed and high-bleed controllers in the transmission segment is
14 from Table 5-2 of U.S. EPA’s Technical Support Document for Subpart OOOOa (NMED
15 Exhibit 70). The data for the VOC emission rate from intermittent bleed controllers in the
16 transmission segment comes from Table W–3B to Subpart W of 40 CFR Part 98. *See* NMED
17 Exhibit 98 – 81 Fed. Reg. 86517, *Greenhouse Gas Reporting Rule: Leak Detection Methodology*
18 *Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems*
19 (November 30, 2016).

20 The fraction of wells subject to either NSPS Subpart OOOO or OOOOa were determined
21 based on well production dates found in the PRRC well data in the 2020 Producing Wells
22 Spreadsheet. *See* NMED Exhibit 94. NSPS Subparts OOOO and OOOOa require certain
23 pneumatic devices at oil and gas sites constructed after a certain date to be low-emitting or non-

1 emitting. The NM OCD well data were used to adjust the estimates of current emissions to
2 reflect the fact that certain percentages of sites in the Subject Counties are subject to federal
3 regulations, and thus have lower emissions as a result.

4 The fraction of pneumatic controllers that cannot be replaced for safety and/or process
5 reasons (12.5%) is based on two technical documents. First, the regulatory analysis for the 2014
6 amendments to Colorado Reg. 7 assumed that 95% of high-bleed pneumatic controllers could
7 eventually be replaced and 5% are needed for safety or process reasons. *See* NMED Exhibit 71.
8 Second, the Technical Support Document for NSPS Subpart OOOOa assumed an 80%
9 replacement rate for high-bleed pneumatic controllers and 20% are needed for safety or process
10 reasons. *See* NMED Exhibit 70. The estimate of 12.5% of high-bleed controllers that cannot be
11 replaced is the midpoint between the Colorado and the EPA estimates.

12 The formulas for the emissions calculations for baseline VOC emissions and the VOC
13 emission reductions using the factors described above that would result from the requirements in
14 Section 20.2.50.122 are detailed in the Pneumatics Reductions and Costs VOC Spreadsheet. *See*
15 NMED Exhibit 95.

16 ERG researched the technical literature and determined the types of replacement
17 pneumatic devices needed to reduce VOC emissions. A primary determinant of the suitability of
18 a replacement device is whether a site already has electric power. ERG estimated the percentage
19 of well sites, gathering/boosting stations, and transmission/compression stations sites in the
20 Subject Counties that have existing electrical power using the NMED Equipment Data. That data
21 indicates that 10.9% of wellhead/tank battery sites, 3.9% of gathering/boosting stations, and
22 100% of transmission/compression stations have electrical generator engines onsite. Because not
23 all 47,937 well sites are reflected in the NMED Equipment Data, ERG's assumption regarding

1 access to electrical power at wells is likely an over-estimate of the fraction of wells with access
2 to electric power.

3 For sites with electric power onsite, information suggests the least expensive option for
4 retrofitting pneumatic devices onsite is to install instrument air. *See* NMED Exhibit 99 – EPA
5 OAR: Natural Gas Star, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air*
6 (October 2006). This involves installing a compressor, air dryer, air tanks, controls, and
7 plumbing to replace the available compressed natural gas that currently powers the onsite
8 pneumatic devices with compressed atmospheric air. Existing pneumatic devices are left in place
9 and the site is re-plumbed to bring compressed air to each pneumatic device. Reductions in VOC
10 emissions resulting from replacement of existing natural gas-powered pneumatic devices with
11 instrument air-powered pneumatic devices are assumed to be 100% because the instrument air is
12 compressed ambient air. ERG assumed that intermittent bleed, low bleed, and high-bleed
13 pneumatic devices could be powered with instrument air systems. This latter assumption is
14 supported by data in the EPA GHGRP for Petroleum and Natural Gas Systems (40 CFR 98,
15 Subpart W) indicating that natural gas processing plants, which all have access to electrical
16 power, already have 100-percent non-emitting controllers and pumps.

17 For sites without electric power onsite, available information indicates that the least
18 expensive option for retrofitting pneumatic devices onsite is to install solar electric controller
19 systems or solar-powered pumps. This approach is based on: (1) a technical paper prepared by
20 Carbon Limits for EPA's Office of Air Quality Standards, *Zero Emissions Technologies for*
21 *Pneumatic Controllers in the USA* (2016), attached as NMED Exhibit 110; and (2) EPA's
22 Technical Support Document for NSPS Subpart OOOOa (NMED Exhibit 70). Solar electric
23 systems involve installing solar panels, battery banks and a system controller, and replacing the

1 pneumatic controllers with electric powered controllers. Reductions in VOC emissions resulting
2 from replacement of existing pneumatic devices with solar electric controllers and pumps are
3 assumed to be 100%. ERG assumed that intermittent bleed, low bleed, and high-bleed pneumatic
4 devices could be powered with solar electric systems. This latter assumption is supported by data
5 from the EPA GHGRP for Petroleum and Natural Gas Systems (40 CFR 98, subpart W)
6 indicating that natural gas processing plants, which all have access to electrical power, already
7 have 100-percent non-emitting controllers and pumps and that commercial line electrical power
8 is equivalent to solar electric power.

9 The Pneumatics Reductions and Costs Spreadsheet compiled by ERG allows the user to
10 select which reduction options they wish to model for both VOC reductions (tpy) and costs of
11 replacements (\$). *See* NMED Exhibit 95, “Emissions and Costs” tab. For each scenario in the
12 spreadsheet (i.e., combinations of Permian/San Juan; Wellhead/Gathering and Boosting/Natural
13 Gas Processing/Transmission and Compression; Low-bleed/intermittent-bleed/high-bleed/pump;
14 Sites with electric/Sites without electric), the user can choose whether to add new replacement
15 controls by selecting ‘1’ or ‘0’ in the spreadsheet. The spreadsheet then generates estimates of
16 the percent reduction in VOC emissions and the cost of that option. This flexibility and
17 programmability allowed ERG to estimate the reductions and costs as the requirements in
18 20.2.50.122.B(4)(c) are phased in over time. Although there is no single set of choices that fulfils
19 those proposed requirements, ERG modeled a set of choices that roughly approximate the long-
20 term objective of the requirements, specifically, an 80% or greater reduction in the number of
21 emitting controllers at well sites, tank batteries, and gathering/boosting stations and a 98%
22 reduction in the number of emitting controllers at natural gas compression/transmission stations
23 and natural gas processing plants.

1 Costs of VOC Reductions from Pneumatic Controllers and Pneumatic Pumps

2 ERG estimated the annualized costs of reducing VOC emissions from the estimated
3 112,500 emitting pneumatic devices to meet the January 1, 2030 standard proposed in Tables 1
4 and 2 of 20.2.50.122.B(3) (approximately a 95% reduction in the number of emitting pneumatic
5 devices) is estimated at \$86,038,000 per year. ERG estimated that the proposed standard will
6 reduce VOC emissions from pneumatic devices by 90.6% from the baseline of 34,600 tpy VOC.

7 In estimating costs and emission reductions for emitting pneumatic devices, it is
8 important to note that the estimated total number of pneumatic devices at well sites/tank batteries
9 is essentially an order of magnitude higher than the estimated total number of pneumatic devices
10 at gathering and boosting stations, which is essentially an order of magnitude higher than the
11 estimated total number of pneumatic devices at transmission/compression stations, and it is
12 estimated that there are no emitting pneumatic devices currently in use at natural gas processing
13 plants. Thus, achieving significant reductions in VOC emissions will require replacement of
14 emitting devices primarily at the upstream end of the production chain.

15 **Section 20.2.50.123 – Storage Vessels**

16 Applicability

17 Section 20.2.50.123 applies to new and existing storage vessels with a PTE equal to or
18 greater than 2 tpy of volatile organic compounds (VOC) and located at well sites, tank batteries,
19 gathering and boosting stations, natural gas processing plants, or natural gas compressor stations.

20 Description of Equipment and Process

21 Storage vessels, commonly referred to as “storage tanks” or “tanks,” are used throughout
22 the oil and gas industry for storing a variety of liquids including crude oil, condensates, and
23 produced water. These tanks are associated with oil and gas production, gathering, processing,

1 and disposal and are significant sources of VOC emissions. Storage vessels can be installed as a
2 single unit or in a grouping of similar or identical vessels, commonly referred to as a “tank
3 battery.” The reason for temporary storage is for feasibility of takeaway via pipeline or truck.

4 While underground and at reservoir pressure, crude oil contains many lighter
5 hydrocarbons in solution. When the oil is brought to the surface, many of the dissolved lighter
6 hydrocarbons (as well as water) are removed through a series of separators. Crude oil is passed
7 through either a two-phase separator (where the associated gas is removed, and any oil and water
8 remain together) or a three-phase separator (where the associated gas is removed, and the oil and
9 water are also separated). The remaining oil is then directed to a storage vessel where it is stored
10 for a period of time before being transported off-site. Much of the remaining hydrocarbon gases
11 in the oil are released as vapors in the storage vessels.

12 Hydrocarbon emissions from storage vessels are a function of flash, breathing (or
13 standing), and working losses. Flash losses occur when a liquid with entrained gases is
14 transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing
15 entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas industry,
16 flashing losses occur when crude oils or condensates flow into a storage vessel at atmospheric
17 pressure from a processing vessel (e.g., a separator) operated at a higher pressure. In general, the
18 larger the pressure drop, the more flash emissions will occur in the storage vessel. The
19 temperature of the liquid may also influence the amount of flash emissions. Breathing losses are
20 the release of gas associated with temperature fluctuations and the expansion and contraction of
21 stored fluids resulting from increased or decreased pressures associated with environmental and
22 weather-related fluctuations. Working losses occur when vapors are displaced due to the
23 emptying and filling of a storage vessel.

1 The mass of gas vapor emitted from a storage vessel depends on many factors. Lighter
2 crude oils flash more hydrocarbons than heavier crude oils. In storage vessels where the oil is
3 frequently cycled and the throughput is high, working losses are higher. Additionally, the
4 operating temperature and pressure of oil in the separator dumping into the storage vessel will
5 affect the volume of flashed gases coming off of the oil. The composition of the vapors from
6 storage vessels varies, and the largest component is methane, but may also include ethane,
7 butane, propane, and hazardous air pollutants such as benzene, toluene, ethylbenzene and
8 xylenes (commonly referred to as BTEX), and n-hexane.

9 Control Options for Storage Vessels

10 The methods typically used to reduce VOC emissions from storage tanks are:

- 11 (1) route emissions from the storage vessel through an enclosed system to a process
12 where emissions are recycled or recovered (e.g., by installing a vapor recovery unit
13 (VRU) that recovers vapors from the storage vessel) for reuse in the process or for
14 beneficial use of the gas onsite; and/or
15 (2) route emissions from the storage vessel to a combustion device.

16 One of the clear advantages the “recycling and recovery” option has over the combustion device
17 option is that it results in a cost savings associated with the recycled, recovered, and reused
18 natural gas and other hydrocarbon vapor, rather than the loss and destruction of the natural gas
19 and vapor by combustion. Combustion and partial combustion of organic pollutants also create
20 secondary pollutants including nitrogen oxides, carbon monoxide, sulfur oxides, carbon dioxide
21 and smoke/particulates.

22 The emission control methods are described below along with their emission reduction
23 control effectiveness.

1 *Routing Emissions to a Process via a Vapor Recovery Unit*

2 One option for controlling storage vessel emissions is to route vapors from the storage
3 vessel back to the inlet line of a separator, to a sales gas line, or to some other line carrying
4 hydrocarbons for beneficial use, such as use as a fuel. Where a compressor is used to boost the
5 recovered vapors into the line, it is often referred to as a vapor recovery unit (“VRU”). With a
6 typical VRU, hydrocarbon vapors are drawn out of the storage vessel under low pressure and
7 then piped to a separator or suction scrubber to collect any condensed liquids, which are usually
8 recycled back to the storage vessel. Vapors from the separator flow through a compressor that
9 provides the low-pressure suction for the VRU system where the recovered hydrocarbons can be
10 transported to various end uses such as a sales line or for use onsite as fuel.

11 Types of VRUs include conventional VRUs, venturi ejector vapor recovery units
12 (“EVRUTM”), and vapor jet VRUs. Decisions on what type of VRU to use are based on the
13 applicability needs (e.g., an EVRUTM is recommended where there is a high-pressure gas
14 compressor with excess capacity, whereas a vapor jet VRU is recommended where there is
15 produced water, less than 75 million cubic feet (MMcf)/day gas, and discharge pressures below
16 40 pounds per square inch gauge (psig)). The reliability and integrity of the compressor and
17 suction scrubber and the integrity of the lines that connect the tank to the compressor will impact
18 the effectiveness of the VRU system to collect and recycle vapors. A conventional VRU is
19 equipped with a control pilot to shut down the compressor and allow the back flow of vapors into
20 the tank in order to prevent the creation of a vacuum in the top of a tank when liquid is
21 withdrawn and the liquid level drops. Vapors are then either sent to the pipeline for sale or used
22 as onsite fuel. Figure 1 presents a diagram of a conventional VRU installed on a single crude oil
23 storage vessel (multiple tank installations are also common).

Conventional VRU

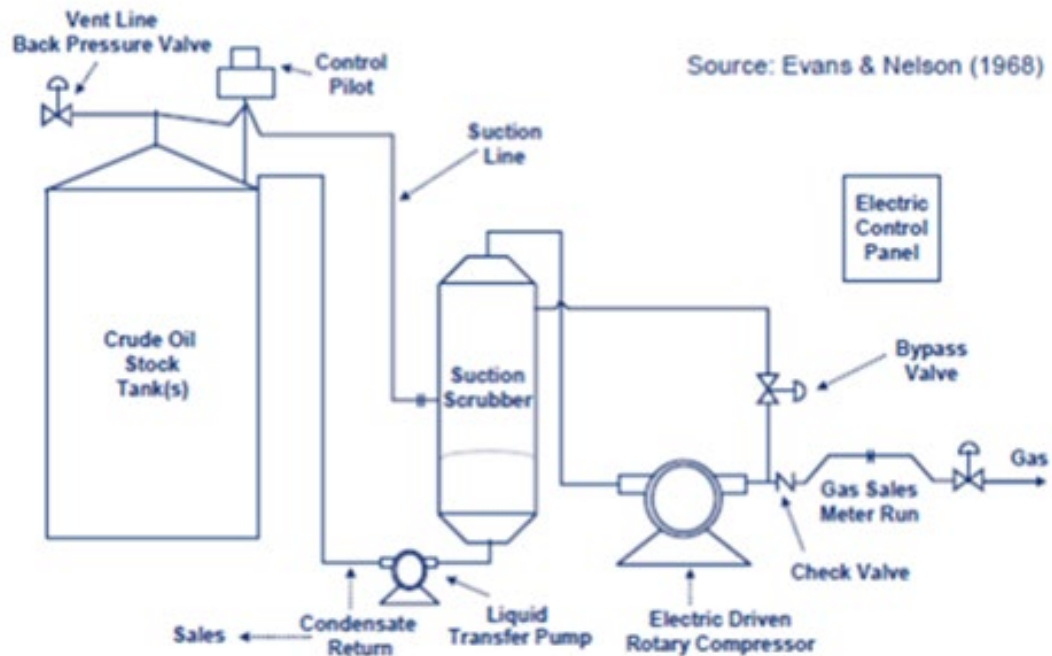


Figure 1. Conventional Vapor Recovery System

Routing Emissions to a Combustion Device

Combustors (e.g., enclosed combustion devices, thermal oxidizers, and flares) are also used to control emissions from storage vessels. Combustors are used to control VOC in many industrial settings, since the combustor can normally handle fluctuations in concentration, flow rate, heating value, and the fraction of inert (i.e., noncombustible or unreactive) gas species. For purposes of this analysis, it was assumed that the types of combustors installed in the oil and natural gas industry can achieve at least a 95% control efficiency on a continuing basis. Note that combustion devices can be designed to meet 98% control efficiencies, and can control on average emissions by 98% on average, or more in practice when properly operated. Combustion devices that are designed to meet a 98% control efficiency may not continuously meet this efficiency in practice, due to factors such as variability of field conditions. A typical combustor

used to control emissions from storage vessels in the oil and natural gas industry is an enclosed combustion system. The basic components of an enclosed combustion system include: (1) piping for collecting emission source gases; (2) a single- or multiple-burner unit; (3) a stack enclosure; (4) a pilot flame to ignite the mixture of emission source gas and air; and (5) combustor fuel/piping (as necessary). Figure 2 presents a schematic of a typical dual-burner enclosed combustion system.

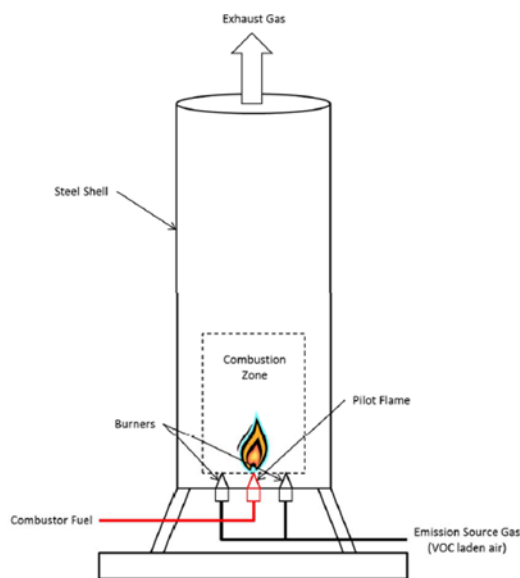


Figure 2. Schematic of a Typical Enclosed Combustion System

Thermal oxidizers, also referred to as direct flame incinerators, thermal incinerators, or afterburners, are also used to control VOC emissions. Similar to a basic enclosed combustion device, a thermal oxidizer uses burner fuel to maintain a high temperature (typically 800-850°C) within a combustion chamber. The VOC-laden emission source gas is injected into the combustion chamber where it is oxidized (burned), and then the combustion products are exhausted (i.e., vented) to the atmosphere. *See* NMED Exhibit 34 (EPA CTG).

1 Proposed Rule Requirements for Storage Vessels

2 Section 20.2.50.123 requires owners and operators of existing storage vessels with a PTE
3 equal to or greater than 2 tpy and less than 10 tpy of VOCs to maintain a combined VOC capture
4 and control efficiency of at least 95% no later than three years after the effective date of Part 50.
5 Owners and operators of existing storage vessels with a PTE equal to or greater than 10 tpy are
6 required to maintain a combined VOC capture and control efficiency of at least 98% no later
7 than one year after the effective date of Part 50.

8 Owners and operators of new storage vessels with a PTE equal to or greater than 2 tpy
9 and less than 10 tpy of VOCs are required to maintain a combined VOC capture and control
10 efficiency of at least 95% percent upon startup. Owners and operators of new storage vessels
11 with a PTE equal to or greater than 10 tpy are required to maintain a combined VOC capture and
12 control efficiency of at least 98% upon startup.

13 The requirements of Section 20.2.50.123 will cease to apply if the uncontrolled actual
14 annual VOC emissions decrease to less than 2 tpy.

15 Should an owner or operator fail to install a control device by the specified dates, they
16 may comply with the emission standards by shutting in the well supplying the storage vessel by
17 the applicable date, and not resuming production from the well until the control device has been
18 installed and operational.

19 Owners or operators that employ a control device to comply with the emission standards
20 of Section 20.2.50.123 NMAC are also required to comply with the control device operational
21 requirements of 20.2.50.115 NMAC.

22 Owners or operators of a new or existing storage vessel equipped with a thief hatch are
23 required to install a device that allows the thief hatch to open sufficiently to relieve vessel

1 overpressure, and to automatically close once the vessel overpressure has been relieved. The
2 thief hatch must be equipped with a manual lock-open safety device to ensure that the hatch
3 remains open during times of human ingress, and shall only be engaged when an owner or
4 operator is present and during active human ingress.

5 Owners or operators of any storage vessel subject to this Section must install an EMT on
6 the storage vessel in accordance with Section 20.2.50.112 NMAC.

7 Owners or operators of a storage vessel subject to Part 50 must comply with certain
8 monitoring requirements, including monthly monitoring of the total monthly liquid throughput
9 and the upstream separator pressure; conducting an AVO inspection on a weekly basis; monthly
10 inspections of the vessel to ensure compliance with Section 20.2.50.123; scanning the EMT and
11 entering the required monitoring data in accordance with the requirements in Section
12 20.2.50.112; complying with the monitoring requirements in Section 20.2.50.115 if using a
13 control device; and complying with the general monitoring requirements in Section 20.2.50.112.

14 The recordkeeping requirements in Section 20.2.50.123 include: monthly records of the
15 vessel location and identification number; monthly liquid throughput and the most recent date of
16 measurement; average monthly upstream separator pressure; data and methodology used to
17 calculate the PTE of VOCs; the controlled and uncontrolled VOC emissions; and the type, make,
18 model, and identification number of any control device.

19 A record of liquid throughput must be verified by a dated delivery receipt from the
20 purchaser of the hydrocarbon liquid, the metered volume of hydrocarbon liquid sent downstream,
21 or other proof of transfer.

22 An owner or operator is required to maintain records of inspections conducted in
23 accordance with Section 20.2.50.123; records required by Section 20.2.50.115 if using a control

1 device to comply with the emission standards of this Section; and the recordkeeping
2 requirements contained in Section 20.2.50.112.

3 An owner or operator must comply with the general reporting requirements in Section
4 20.2.50.112, and must also comply with the reporting requirements of Section 20.2.50.115 if
5 using a control device.

6 Basis for Proposed Rule Requirements

7 The proposed requirements are based on similar rules for new and existing storage
8 vessels in Pennsylvania GP-5 and GP-5A, Colorado Reg. 7, and NSPS Subpart OOOOa.²⁴ See
9 NMED Exhibits 37, 38, and 39, respectively.

10 The applicability threshold in Section 20.2.50.123 is based on Colorado Reg. 7, Section
11 I.D.1.a. The proposed emission standard in 20.2.50.123.B(1) and (3), requiring all existing and
12 new storage vessels with a PTE equal to or greater than 2 tpy VOC to have a combined capture
13 and control efficiency of 95 percent for VOC emissions, is based on Pennsylvania GP-5A,
14 Section E.1.(b) and Colorado Reg. 7, Section I.D.3.a.(i). Pennsylvania GP-5 and GP-5A require
15 an owner or operator to equip the storage vessel with a cover and route all vapor through a closed
16 vent system to a control device that reduces VOC emissions by 95% or more. Colorado Reg. 7
17 requires owners and operators of existing and new storage vessels with uncontrolled actual
18 emissions of VOCs equal to or greater than 2 tpy to collect emissions and route them to pollution
19 control equipment that achieves a VOC control efficiency of 95%. If a combustion device is
20 used, it must have a design destruction efficiency of at least 98% for VOC. NSPS Subpart
21 OOOOa has similar requirements, requiring owners or operators of storage vessels with a PTE

²⁴ U.S. EPA, New Source Performance Standards for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced after September 18, 2015, June 2016.
Available at: <https://www.epa.gov/stationary-sources-air-pollution/crude-oil-and-natural-gas-facilities-which-construction>

1 equal to or greater than 6 tpy of VOC to reduce VOC emissions by 95%. *See* NMED Exhibit 36,
2 at Sections 60.5365a(e) and 60.5395a(a)(2).

3 The proposed emission standards in Section 20.2.50.123.B(2) and (4) require that
4 existing and new storage vessels with a PTE equal to or greater than 10 tpy of VOC have a
5 combined capture and control efficiency of 98% for VOC emissions. The standards are based on
6 the requirements of the Pennsylvania GP-5A, Section E.1.(b) and Colorado Reg. 7, Section
7 I.D.3.a.(i), but were adjusted to require additional VOC emissions reductions for those storage
8 vessels with higher VOC emissions (PTE greater than 10 tpy VOC).

9 Estimated Emissions Reductions

10 Based on the NMED Equipment Data, ERG identified 3,921 affected storage tanks in the
11 Subject Counties for the year 2020. Of these, 2,059 are uncontrolled and unregulated by NSPS
12 Subpart OOOO and NSPS Subpart OOOOa. Of these 2,059 storage vessels, 53% (1,040 storage
13 vessels) have allowable emissions equal to or greater than 2 tpy of VOC and would be subject to
14 the requirement to control emissions under Part 50.

15 The proposed rule requires a 95% reduction of VOC emissions for tanks with a PTE
16 equal to or greater than 2 tpy of VOC, and a 98% reduction for tanks with a PTE equal to or
17 greater than 10 tpy of VOC. Emission reductions were not calculated for those tanks that already
18 have a VOC control device (e.g., condenser, VRU, or flare), that are already subject to NSPS
19 Subparts OOOO or OOOOa, or that have allowable VOC emissions less than 2 tpy. Applying
20 these emission reductions results in estimated VOC emission reductions of 8,585 tons per year
21 for an overall reduction of 53%. *See* NMED Exhibit 100 – Storage Tanks Reductions and Costs
22 VOC Spreadsheet.

1 Costs of VOC Reductions from Storage Vessels

2 The annualized costs of reducing VOC emissions from the estimated 2,059 uncontrolled
3 and unregulated storage vessels is approximately \$16,039,252. This annualized cost includes
4 capital and installation costs, as well as operation and maintenance costs for installing
5 combustors at 495 sites, and also includes the costs for retrofitting tanks to add the vent system
6 and piping to route emissions to the control device. Because multiple tanks are typically installed
7 at one location, the services of a combustor are assumed to be shared amongst all the tanks.

8 The capital and annual costs per combustor are based on cost figures provided in Table 4-
9 5 - Total Capital Investment and Total Annual Costs of a Combustor in the EPA CTG (NMED
10 Exhibit 34). The cost effectiveness estimates (measured in cost per ton of VOC reduced) for
11 routing VOC emissions from an existing uncontrolled storage vessel to a combustion device are
12 based on cost figures in Table 4-6 of EPA CTG.

13 Costs were updated to reflect 2019 costs using the CEPCI of \$584.6 for 2012 and \$607.5
14 for 2019. The 2019 annualized cost ratio is therefore estimated as:

15
$$607.5/584.6 = 1.04$$

16 The Storage Tanks Reductions and Costs Spreadsheet provides a detailed breakdown of
17 costs. *See* NMED Exhibit 100.

18 **Section 20.2.50.124 – Well Workovers**

19 Applicability

20 Section 20.2.50.124 applies to workovers performed at oil and natural gas wells.

21 Description of Process

22 Some wells require supplementary maintenance to maintain production or minimize the
23 decline in production. These operations are referred to as workovers. Typical workovers include

1 rod, tubing and casing repairs; siphon string or artificial lift installation paraffin removal; and
2 pump repairs.

3 Workovers are performed on wells that have previously been completed and have
4 produced some reservoir fluids (water, oil, and/or natural gas). These wells have to be prepared
5 before workover operations can begin. If the well is still producing and/or has pressure, the well
6 will need to be blown down (i.e., vented) before it is safe to remove the tubing head and install
7 the blowout preventers (“BOPs”). The well pressure can be decreased by venting to the
8 atmosphere or by opening the casing to the sales line or the suction of a wellsite compressor. In
9 many cases, the fluids in the wellbore will build up to the point the well “dies” – this refers to the
10 instance where the hydrostatic pressure of the accumulated fluids is equal to the reservoir
11 pressure. In some cases, it will be necessary to pump water or other fluids into the wellbore to
12 “kill” the well. As a safety precaution, after the BOPs are installed, the well is usually vented to
13 atmosphere via a tank.

14 Workovers are usually short duration projects that only last a few days or weeks at the
15 most. After the well is prepared (i.e., blown down and BOPs installed), the workover operations
16 can begin. For the safety of the rig crew, the well is usually allowed to vent to atmosphere via a
17 tank for the duration of the workover. Since these operations are typically performed during
18 daylight hours, the well is shut in or returned to the sales line at the end of the day.

19 Control Options

20 Best management practices are the best means of reducing emissions during well
21 workovers. These include reducing wellhead pressure before blowdown to minimize the volume
22 of natural gas vented; monitoring manual venting at the well until the venting is complete; and
23 routing natural gas to the sales line, whenever possible.

1 Proposed Rule Requirements for Well Workovers

2 The owner or operator of an oil or natural gas well must use the following best
3 management practices during a workover to minimize emissions, consistent with the well site
4 condition and good engineering practices: (1) reduce wellhead pressure before blowdown to
5 minimize the volume of natural gas vented; (2) monitor manual venting at the well until the
6 venting is complete; and (3) route natural gas to the sales line, if possible.

7 During a well workover, an owner or operator is required to monitor wellhead pressure,
8 natural gas venting flow rate, and elapsed venting time in order to calculate the volume and mass
9 of VOC vented during a well workover. For each workover, the owner or operator must record
10 the identification number and location of the well; date; wellhead pressure; flow rate or
11 maximum potential flow rate; duration of venting; best management practices used; and the
12 quantity of VOC emissions released. When venting cannot be avoided, the owner and operator
13 must notify all residents located within one-quarter mile of the well at least three days before the
14 workover by certified mail. In addition, the owner or operator shall comply with the general
15 monitoring, recordkeeping, and reporting requirements in Section 20.2.50.112.

16 Basis for Proposed Rule Requirements

17 The proposed requirements for workover operations are based on requirements in
18 Colorado Reg. 7 and Wyoming's Permitting Guidance. *See* NMED Exhibits 39 and 40,
19 respectively.

20 Colorado Reg. 7, Section II.G requires owners and operators to use best management
21 practices to minimize hydrocarbon emissions associated with downhole well maintenance, well
22 liquids unloading, and well plugging unless emitting is necessary for safety. The Colorado rule

1 also requires the owner or operator be present onsite and minimize emissions to the maximum
2 extent practicable.

3 Wyoming's Permitting Guidance requires minimizing emissions to the extent practicable
4 during manual and automated blowdown/venting episodes associated with liquids unloading,
5 wellbore depressurization in preparation for maintenance or repair, and other well operations.
6 The guidance requires personnel to remain onsite to ensure minimal gas venting occurs, and also
7 requires that operators estimate the duration of venting episodes and the amount of VOC emitted
8 during such events. *See* NMED Exhibit 40, at pp. 13, 19, and 24.

9 EPA did not regulate emissions from well workovers or blowdown operations in NSPS
10 Subparts OOOO or OOOOa. The EPA CTG did not address emissions from these operations.
11 *See* NMED Exhibit 34.

12 Estimated Emissions Reductions

13 Emission estimates for workover operations are not currently available in the modeling
14 emissions inventory or found in the NMED Equipment Data. Therefore, no estimate of emissions
15 reductions is currently available.

16 Estimated Costs

17 Section 20.2.50.124 specifies certain best management practices that must be used when
18 conducting well workover operations, but does not require the use of emission control devices. It
19 is expected that these practices will require personnel to manage the well during the workover
20 operation, but no capital costs are anticipated. Costs associated with well workover best
21 management practices are expected to be minimal as personnel will already be onsite conducting
22 the well workover and any additional training may be incorporated into existing personnel
23 training programs.

Section 20.2.50.126 – Produced Water Management Units

Applicability

Section 20.2.50.126 applies to produced water management units (“PWMU”), which are defined in Section 20.2.50.7.II as follows:

[A] recycling facility or a permanent pit that is a natural topographical depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to accumulate produced water and has a design storage capacity equal to or greater than 50,000 bbls.

Description of Process

The majority of oil- and gas-bearing formations also contain naturally occurring water, often referred to as “formation” or “connate” water. When oil or gas is extracted, this “produced water” is also extracted as a by-product. The actual amount of produced water varies widely depending on factors such as location or stage in the lifetime of a particular well. In addition to reflecting the chemical makeup of the geologic formation from which it is extracted, produced water will also contain suspended solids, dissolved solids, varying amounts of oil residues and organics containing VOCs, and the various chemicals used in the production process. Produced water from gas production typically has higher contents of low molecular-weight aromatic hydrocarbons, such as benzene, toluene, ethylbenzene, and xylene (“BTEX”) than produced water from oil production.

Conventional Oil and Gas

On average, about 7 to 10 barrels, or 280 to 400 gallons, of water are produced for every barrel of crude oil. Oil reservoirs commonly contain larger volumes of water than gas reservoirs

1 because gas is stored and produced from less porous reservoirs that contain source rock with a
2 lower water capacity. Produced water generation commonly increases over time in conventional
3 reservoirs as the oil and gas is depleted during hydrocarbon production. *See* U.S. Dept. of
4 Interior, Bureau of Reclamation Science and Technology Program Report No. 157, *Oil and Gas*
5 *Produced Water Management and Beneficial Use in the Western United States* (September
6 2011).²⁵

7 *Unconventional Oil and Gas*

8 Produced water from most unconventional resources, besides coal bed methane, is
9 minimal due to tighter reservoir formations such as tight sands, oil shale, and gas shale
10 reservoirs. Producers commonly import water to these operations for onsite use in drilling,
11 fracturing, and production. Fresh water used in drilling applications for fracturing is
12 contaminated by the saline water in the reservoir. Fresh water brought onsite for use in
13 operations, such as flow back or water returning from fracturing applications (“frac water”), also
14 is managed as a waste stream. This waste stream is commonly associated with the initial phase of
15 well development and production. In most unconventional oil and gas operations, frac water is
16 considered the largest waste stream of production.

17 Control Options

18 VOC emissions from PWMU can be reduced by treating the produced water to remove
19 hydrocarbons before the water enters the recycling facility or impoundment. The emissions are
20 reduced when produced water is processed through three-phase separators and storage vessels,
21 which separates the hydrocarbons from the produced water prior to sending to a PWMU.

22 Proposed Rule Requirements for Produced Water Management Units

²⁵ Available at: <https://www.usbr.gov/research/dwpr/reportpdfs/report157.pdf>

1 Section 20.2.50.126 requires owners and operators to employ best management and good
2 engineering practices to minimize emissions of VOC from produced water management units.
3 VOC emissions must be controlled to less than two tons per year.

4 Owners and operators must also comply with monitoring, recordkeeping, and reporting
5 requirements that ensure the affected units are being properly operated and maintained in a
6 manner that meets the emissions reduction requirements in the rule. The monitoring
7 requirements include calculating a monthly rolling 12-month total of VOC emissions from each
8 unit. Owners and operators are required to use this monthly rolling total to control VOC
9 emissions to less than two tons per year. The proposed rule requires monthly monitoring of best
10 management and engineering practices applied at each unit to ensure reduced emissions and
11 effectiveness of the practice.

12 Owners and operators are required to maintain records for each produced water unit
13 including its name or identification number; UTM coordinates; county in which its located;
14 description of best management and engineering practices used to minimize VOC releases; and a
15 record of the monthly rolling 12-month total VOC emissions.

16 Produced water management units are also subject to the general monitoring,
17 recordkeeping and reporting requirements in Section 20.2.50.112.

18 Estimated Emission Reductions and Cost

19 Section 20.2.50.126 specifies that best management practices and good engineering
20 practices must be used to minimize VOC emissions at PWMUs, but does not require the use of
21 emission control devices. It is expected that these practices will require personnel to manage the
22 minimization of emissions PWMUs, but no capital costs are anticipated. Costs associated with
23 best management and good engineering practices are expected to be minimal as personnel will

1 already be onsite at the facility, and any additional training may be incorporated into existing
2 personnel training programs.

3 PWMUs are unregulated under the federal Clean Air Act and its implementing
4 regulations, and EPA has not published emission factors specific to this type of operation.

5 NMED's Ongoing Review

6 The Department continues to review scientific and technical information in published
7 literature, engage in discussions with EPA, and review data submitted by owners and operators
8 of PWMUs to determine the most effective and enforceable control strategy to reduce VOC
9 emissions, while preventing unintended public health and environmental consequences that
10 could arise from disincentivizing the recycling and reuse of produced water in the oil and gas
11 industry. NMED is evaluating alternative emission standards to achieve important emissions
12 reductions while continuing to encourage the use of produced water instead of freshwater
13 resources throughout the industry.

14 **Section 20.2.50.127 – Credible Evidence Provisions**

15 Section 20.2.50.127 contains provisions regarding enforcement for violations of Part 50.
16 Subsection A expressly states what is implicit in any mandatory requirement of an air quality
17 regulation under the CAA or the AQCA: that failure to comply with any of the requirements in
18 Part 50 within the specified timeframes constitutes a violation of Part 50 that is subject to
19 enforcement action under the AQCA. This Section provides clear notice to the regulated
20 community that failure to comply with the provisions of Part 50 will be subject to enforcement.

21 Subsection B provides that if the Department obtains credible information indicating that
22 a source is not in compliance with Part 50, the source will be presumed to be in violation unless
23 and until the owner or operator provides credible evidence or information demonstrating that

1 there is no violation. Subsection C establishes a similar presumption of violation if the
2 Department receives credible information from a member of the public. These provisions
3 establish a presumption of a violation of Part 50 when the Department comes into possession of
4 credible information – either obtained by the Department pursuant to an inspection or records
5 request, or provided to the Department by an outside person – that indicates noncompliance. This
6 presumption can then be rebutted by the owner or operator through credible evidence or
7 information showing that no violation occurred.

8 By placing the burden on the regulated entity to affirmatively show that it is in
9 compliance with Part 50, the provisions of Section 20.2.50.127 give the Department an important
10 tool in ensuring that the public health and the environmental protections of Part 50 are actually
11 realized. Regulations have little benefit if they cannot be enforced. These provisions help
12 alleviate the staffing and resource constraints that limit the Department’s ability to physically
13 inspect sources and identify violations. Further, Subsection C allows the Department to take
14 advantage of the increasing access that the public has to advanced emissions monitoring
15 technologies that can be used to monitor and record a facility’s operations and that can be used
16 as evidence in enforcement cases. Such technologies include infrared cameras. Surveillance
17 monitoring and infrared imaging conducted by non-governmental organizations can be
18 compelling, and has been used by the Department to support allegations of air quality violations
19 in past enforcement actions.

20 Importantly, the provisions of Section 20.2.50.127 do **not** establish that any evidence or
21 information received or obtained by the Department is presumed to be credible. The Department
22 still has the authority to determine that information is “credible” before any violation will be
23 presumed based on that information. The term “credible evidence” is widely used throughout

1 environmental and other regulatory provisions. As used in Subsection 20.2.50.127, the term
2 “credible” is intended to have the same meaning as explained by EPA in the background to its
3 “Credible Evidence Rule” at 62 Fed. Reg. 8314. *See* NMED Exhibit 101. As explained by EPA
4 in pertinent part:

5 The Federal Rules of Evidence govern the admission of evidence in all federal
6 district court litigation, including CAA enforcement actions Similar
7 evidentiary rules govern federal administrative and state environmental actions.
8 Our legal system provides that a federal or administrative law judge will be the
9 ultimate, independent arbitrator of the evidence's admissibility and credibility.

10
11 Credible evidence is far from a new concept in judicial and administrative actions.
12 In private lawsuits such as contract disputes, and in governmental and citizen
13 enforcement actions brought under environmental laws other than the CAA,
14 litigants can and do use a wide variety of information to prove their claims, or to
15 refute the claims of opposing parties. In all these lawsuits, the judge acts as the
16 final, independent arbitrator of what constitutes credible and admissible evidence.

17
18 It should be emphasized that the determination that evidence or information is
19 credible is merely a threshold determination that the evidence or information in
20 question is technically relevant, and therefore, legally admissible in an
21 enforcement action. In light of [Clean Air Act] section 113(a) providing that the
22 Administrator may bring an enforcement action based on "any information", EPA
23 believes that Congress intended this threshold to be a low one.

24
25 *Id.* at 8317-8318.

26 Like the Clean Air Act, the AQCA provides that the Secretary of the Department may bring an
27 enforcement action based on “any information.” *See* NMSA 1978, § 74-2-12(A).

Brian Palmer

Senior Scientist



A experienced scientist with expertise in characterizing and managing emissions from the oil and gas (O&G) sector

- Since May 2020, has been developing a proposed rule to reduce VOC and NOx emissions from oil and gas production and transmission operations in New Mexico.
- Developed proposed amendments to 40 CFR part 98, subpart W, Mandatory Greenhouse Gas Reporting for Petroleum and Natural Gas Systems.
- Led regulatory development projects for 15 source categories, including developing baseline emission inventories and estimating emission reductions.
- Has supported numerous projects related to 40 CFR part 98, Mandatory Greenhouse Gas Reporting.

EMPLOYMENT

1996–present

Senior Environmental Scientist, ERG, Morrisville, NC

1991–1996

Environmental Scientist, Radian International LLC, Morrisville, NC

EDUCATION

M.A., Ecology, University of North Carolina at Chapel Hill, 1991

B.S., Biology, Bates College, 1984

RELEVANT PROJECTS

New Mexico Ozone Precursor Rule for the Oil and Natural Gas Sector

Client: New Mexico Environment Department (NMED). Developing a proposed rule to reduce emissions of VOC and NOx from oil and natural gas production in New Mexico. Identifying achievable control levels for each emission source types using federal NSPS, CTGs, and other state rules. The proposed rule will cover engines and turbines, compressor seals, equipment leaks, gas well liquids unloading, glycol dehydrators, process heaters, liquid transfers from storage tanks to trucks and rail cars, pig launching and receiving, pneumatic controllers and pumps, storage tanks, well workovers, and evaporation ponds for produced water disposal. For each source type, estimating the potential percent emission reductions and the control costs, accounting for the number of sources that already have controls or that are already subject to a NSPS or NESHAP that would require the same level of control as the proposed rule. Analyzed equipment data for permitted facilities provided by NMED. For the cost and emission reductions, reviewed pre-existing cost and emission reduction analyses completed for other federal and state rulemakings, and adapted them for the information available in the equipment data sheets from the NMED. Coordinated the QA of the emission reduction and cost impact analyses and prepared the documentation for the control technology, emission reduction, and cost impact analyses.

Oil and Natural Gas Systems (40 CFR 98, Subpart W) Amendments

Client: EPA/CCD. Oil and Natural Gas Systems (40 CFR 98, Subpart W) Amendments. Directed the preparation of two proposal packages to amend subpart W. In the first package, directed the completion of a proposed rule to amend Subpart W to revise certain calculation methods, monitoring methods, and data reporting requirements. The changes also clarified terms and definitions and corrected certain technical and editorial errors. Directed the completion of the preamble and amendatory text and the technical support documents. Directed the initiation of a second rulemaking to add GHG reporting requirements for completions and workovers of hydraulically fractured oil wells, the natural gas gathering and boosting segment (including equipment located on gathering pipelines, such as compressors, acid gas removal units, dehydrators, metering and valve stations), natural gas transmission pipeline blow downs, and the addition of API Well Numbers to the reporting requirements.

Federal Implementation Plan (FIP) for Oil and Gas Development in Indian Tribal Areas.

Client: EPA/OAQPS/SPPD. Oversaw the development of control options to reduce emissions from oil and gas development on tribal lands to be used as the basis for a FIP and to provide a streamlined permitting option for oil and gas development on tribal lands to avoid the burden on oil and gas developers and permitting agencies of case-by-case permits associated with NSR or PSD. The FIP also considered additional controls for wells located on tribal areas that were in ozone non-attainment areas. Control options were developed for the following oil and gas sources: oil and gas well completions with hydraulic fracturing; oil, gas, and water separators; heater treaters, amine treatment systems; glycol dehydration systems; centrifugal compressors; pneumatic controllers and pneumatic pumps; blowdown venting; equipment leaks; flash tanks; storage tanks; flares (including pit flares, utility flares, and enclosed combustors); truck loading; reciprocating internal combustion engines; external combustion units and process heaters. Controls included the use of flares and closed vent systems, and leak detection and repair programs. Emissions were estimated using data on the actual number of wells on tribal lands compiled from the Drilling Info database using API Well Numbers and well production data. Costs were estimated using cost efficiency data developed from the NSPS for oil and gas development (40 CFR 60, subpart OOOO).

Support for Compliance Monitoring and Assistance for the GHG Reporting Program

Client: EPA/CCD. Coordinates all support activities related to compliance monitoring and assistance for the entire GHGRP, including tracking of expected reporters and dropped reporters, analyzing applicability for expected reporters and comparing them to reporting thresholds, performing outreach to expected and dropped reporters to help bring them into compliance, and performing QA of data and analyses related to compliance monitoring to identify expected and dropped reporters (including comparisons between non-EPA lists of GHG emitting facilities and the EPA database of expected reporters and facilities already reporting to the GHGRP).

Electronics Manufacturing (40 CFR 98, Subpart I) Amendments and Implementation

Client: EPA/CCD. Directed the preparation of a proposed and final rule to amend Subpart I to address the issues raised by the Semiconductor Industry Association (SIA) in a petition for reconsideration. The amendments removed the requirement for certain large facilities to develop and use recipe-specific emission factors for fluorinated GHG (F-GHG) and N₂O emissions from semiconductor manufacturing facilities. The amendments also added a new method for determining emissions from all electronics facilities using stack testing methods, including FTIR, to measure emissions. Developed and presented a Microsoft PowerPoint webinar to explain the new rule amendments to industry GHG reporters.

Implementation included working with other EPA contractors to develop and test the calculation tool and reporting form used by reporters, and developing and testing validation checks for completed forms, and verification checks for reported data. Verification of the data submitted under subpart I in the 2011 to 2013 reporting years, including checks that reporting forms were completed correctly, emissions were estimated and reported consistent with subpart I, and communicating with facilities to ensure that verification issues were resolved. Implementation also included analysis of reported data to identify trends in the data, comparing reported data to other publicly available data sources, identifying variables that could predict emissions, and determining the fraction of total industry emissions represented by the reported emissions, and extrapolating the reported data to the whole industry.

Coordinated the design and testing of a new web-based reporting form to replace the existing spreadsheet-based reporting form. Worked with another EPA contractor to develop a design requirements document, a mock-up of the web form in Excel, and then test the new web form in an EPA staging environment and provide feedback. Developed and presented a PowerPoint webinar explaining to GHG reporters how to use the new web-based form.

GHG Emission Reductions

Client: EPA/CCD. Directed a task in which ERG scientists estimated the potential for future GHG emission reductions from several energy intensive source categories, including pulp and paper plants, refineries, and iron and steel mills. The team estimated potential emission reductions based on recent and forecasted trends in energy consumption for each category and an evaluation of emerging technologies that could affect energy consumption and GHG emitting processes in each category. Estimates included the lower and upper bounds of the emission estimates.

Air Emission Standard Regulatory Development Support

Client: EPA/OAQPS/SPPD. Directed the development of national air emission standards for numerous source categories, including National Emission Standards for Hazardous Air Pollutants, New Source Performance Standards, National VOC Rules, and Control Techniques Guideline Documents. Directed development of new

emission standards for 11 source categories and also risk and technology reviews of standards for 10 source categories that had already been developed and implemented. Has provided technical support for development and implementation of standards for multiple other source categories.

Collected information on each source category from visits to industrial facilities and in meetings between industry representatives and the EPA. Directed the development of an inventory of emission sources and an estimate of baseline emissions. Identified add-on control technologies, work practices, and process modifications that can be used to reduce emissions. Estimated the cost and potential emission reductions of those options. Documented the methodology and results of each analysis. Developed supporting documentation for proposed and final rules, and the preamble and regulatory language. Summarized public comments on proposed rule and developed final rules and supporting preambles.



Control Techniques Guidelines for the Oil and Natural Gas Industry

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October 2016

Control Techniques Guidelines for the Oil and Natural Gas Industry

U.S. Environmental Protection Agency
Office of Air and Radiation
Office of Air Quality Planning and Standards
Sector Policies and Programs Division
Research Triangle Park, North Carolina

DISCLAIMER

This report has been reviewed by EPA's Office of Air Quality Planning and Standards and has been approved for publication. Mention of trade names or commercial products is not intended to constitute endorsement or recommendation for use.

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ACRONYMS AND ABBREVIATIONS

Acronyms/Abbreviations	Description
ACA	Air Compliance Advisor
ANGA	America's Natural Gas Alliance
APCD	Air Pollution Control District
API	American Petroleum Institute
AQMD	Air Quality Management District
ARCADIS	a global consulting firm
bbl/day	barrels per day
boe/day	barrels of oil equivalent per day
BSER	best system of emission reduction
BTEX	benzene, toluene, ethylbenzene and xylenes
Btu	British thermal unit
Btu/scf	British thermal unit per standard cubic feet
CAA	Clean Air Act
CETAC-WEST	Canadian Environmental Technology Advancement Corporation- WEST
Cfm	cubic foot per minute
CFR	Code of Federal Regulations
CH ₄	methane
CMSA	Consolidated Metropolitan Statistical Area
CO	carbon monoxide
CO ₂	carbon dioxide
CTG	Control Techniques Guidelines
E&P Tanks Program	is a personal computer-based software designed to use site-specific information to predict emission from petroleum production storage tanks
ERG	Eastern Research Group
EVRU	ejector vapor recovery units
FIP	Federal Implementation Plan
FR	Federal Register
FRED	Federal Reserve Economic Data
G	Gram
GDP	gross domestic product
GHG	greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
GRI	Gas Research Institute
HAP	hazardous air pollutants

Acronyms/Abbreviations	Description
HPDI database	provides production data and web-enabled analytical software tools for a wide range of oil and gas related customers
H ₂ S	hydrogen sulfide
ICF International	a firm that provides professional services and technology solutions in strategy and policy analysis, program management, project evaluation, and other services
IR	infrared
kg/hr/comp	kilogram per hour per component
kg/hr/source	kilogram per hour per source
kPa	kilopascals
kW	kilowatt
LAER	lowest achievable emission rate
LDAR	leak detection and repair
Mcf	thousand cubic feet
MMcf/yr	million cubic feet per year
NA	Nonattainment
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGL	natural gas liquids
NO _x	nitrogen oxide
NSPS	New Source Performance Standards
O&M	operation & maintenance
OAQPS	Office of Air Quality Planning and Standards
OCCM	OAQPS Control Cost Manual
OEL	open-ended lines
OGI	optical gas imaging
OTR	Ozone Transport Region
OVA	organic vapor analyzer
PG&E	Pacific Gas & Electric
PNAS	Proceedings of the National Academy of Sciences
ppm	parts per million
Ppmv	parts per million by volume
PRV	pressure relief valve
Psi	pounds per square inch
Psia	pounds per square inch absolute
Psig	pounds per square inch gauge
PTE	potential to emit
RACT	reasonably available control technology
RBLC	RACT/BACT/LAER Clearinghouse
Scf	standard cubic feet
Scfh	standard cubic feet per hour

Acronyms/Abbreviations	Description
scfh-cylinder	standard cubic feet per hour-cylinder
Scfm	standard cubic feet per minute
SIP	State Implementation Plan
SO ₂	sulfur dioxide
STSD	supplemental technical support document
THC	total hydrocarbons
TOC	total organic compounds
Tpy	tons per year
TSD	technical support document
TVA	toxic vapor analyzer
U.S.	United States
U.S. EIA	U.S. Energy Information Administration
U.S. EPA	U.S. Environmental Protection Agency
VOC	volatile organic compound
VRU	vapor recovery unit

1.0 INTRODUCTION

Section 172(c)(1) of the Clean Air Act (CAA) provides that state implementation plans (SIPs) for nonattainment areas must include “reasonably available control measures” including “reasonably available control technology” (RACT), for existing sources of emissions. CAA Section 182(b)(2)(A) provides that for Moderate ozone nonattainment areas, states must revise their SIPs to include RACT for each category of volatile organic compound (VOC) sources covered by control techniques guidelines (CTG) documents issued between November 15, 1990, and the date of attainment. Section 182(c) through (e) applies this requirement to states with ozone nonattainment areas classified as Serious, Severe, and Extreme. CAA Section 184(b) requires that states in ozone transport regions must revise their SIPs to implement RACT with respect to all sources of VOC in the state covered by a CTG issued before or after November 15, 1990. CAA Section 184(a) establishes a single Ozone Transport Region (OTR) comprised of the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont and the Consolidated Metropolitan Statistical Area (CMSA) that includes the District of Columbia.

The U.S. Environmental Protection Agency (EPA) defines RACT as “the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.” 44 FR 53761 (September 17, 1979).

This CTG provides recommendations to inform state, local, and tribal air agencies (hereafter, collectively referred to as air agencies) as to what constitutes RACT for select oil and natural gas industry emission sources. Air agencies can use the recommendations in the CTG to inform their own determination as to what constitutes RACT for VOC for the emission sources presented in this document in their Moderate or higher ozone nonattainment area or state in the OTR. The information contained in this document is provided only as guidance. This guidance does not change, or substitute for, requirements specified in applicable sections of the CAA or the EPA’s regulations; nor is it a regulation itself. This document does not impose any requirements on facilities in the oil and natural gas industry. It provides only recommendations for air agencies to consider in determining RACT. Air agencies may implement other

technically-sound approaches that are consistent with the CAA, the EPA's implementing regulations, and policies on interpreting RACT.

The recommendations contained in this CTG are based on data and information currently available to the EPA. The EPA evaluated the sources of VOC emissions in the oil and natural gas industry and the available control approaches for addressing these emissions, including the costs of such approaches. The recommendations contained in this CTG may not be appropriate for every situation based upon the circumstances of a specific source (e.g., VOC content of the gas, safety concerns/reasons). Regardless of whether an air agency chooses to adopt rules implementing the recommendations contained herein, or to issue rules that adopt different approaches for RACT for VOC from oil and natural gas industry sources, air agencies must submit their RACT rules to the EPA for review and approval using the SIP process. The EPA will evaluate the RACT determinations and determine, through notice and comment rulemaking, whether these determinations in the submitted rules meet the RACT requirements of the CAA and the EPA's regulations. To the extent an air agency adopts any of the recommendations in this guidance into its RACT rules, interested parties can raise questions and objections about the appropriateness of the application of this guidance to a particular situation during the development of these rules and the EPA's SIP process. Such questions and objections can relate to the substance of this guidance.

Section 182(b)(2) of the CAA requires that a CTG document issued between November 15, 1990, and the date of attainment include the date by which states subject to CAA section 182(b) must submit SIP revisions. Accordingly, the EPA is setting forth a 2-year period, from the date of publication of the notice of availability of this CTG in the *Federal Register* for the required SIP submittal.

2.0 BACKGROUND AND OVERVIEW

There have been several federal and state actions to reduce VOC emissions from certain emission sources in the oil and natural gas industry. A summary of these actions is provided below.

2.1 History of New Source Performance Standards that Regulate Emission Sources in the Oil and Natural Gas Industry

In 1979, the EPA listed crude oil and natural gas production on its priority list of source categories for promulgation of NSPS (44 FR 49222, August 21, 1979). Since the 1979 listing, the EPA has promulgated performance standards to regulate VOC emissions from production, processing, transmission, and storage as well as sulfur dioxide (SO₂) emissions from natural gas processing emission sources and, more recently, greenhouse gases (GHG). On June 24, 1985 (50 FR 26122), the EPA promulgated an NSPS for natural gas processing plants that addressed VOC emissions from leaking components (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), a second NSPS was promulgated for natural gas processing plants that regulated SO₂ emissions (40 CFR part 60, subpart LLL). On August 16, 2012 (77 FR 49490) (2012 NSPS), the EPA finalized its review of NSPS standards for the listed oil and natural gas source category and revised the NSPS for VOC from leaking components at natural gas processing plants, and the NSPS for SO₂ emissions from natural gas processing plants. At that time, the EPA also established standards for certain oil and natural gas emission sources not covered by the existing standards. In addition to the emission sources that were covered previously, the EPA established new standards to regulate VOC emissions from hydraulically fractured gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers, and storage vessels. In 2013 (78 FR 58416) (2013 NSPS Reconsideration) and 2014 (79 FR 79018), the EPA amended the standards set in 2012 in order to improve implementation of the standards. In 2016 (81 FR 35824, June 3, 2016), the EPA finalized new standards to regulate GHG and VOC emissions across the oil and natural gas source category. Specifically, the EPA finalized both GHG standards (in the form of limitations on methane emissions) and VOC standards for several emission sources not previously covered by the NSPS (i.e., hydraulically fractured oil well completions, pneumatic pumps, and fugitive emissions from well sites and compressor stations).

In addition, the EPA finalized GHG standards for certain emission sources that were regulated for only VOC (i.e., hydraulically fractured gas well completions, centrifugal compressors, reciprocating compressors, pneumatic controllers and equipment leaks at natural gas processing plants). With respect to certain equipment that are used across the industry, 40 CFR part 60 subpart OOOO regulates only a subset of these equipment (pneumatic controllers, centrifugal compressors, reciprocating compressors). The final amendments established GHG standards (40 CFR part 60 subpart OOOOa) for these equipment and extended the current VOC standards to previously unregulated equipment. Although not regulated under the oil and natural gas NSPS, stationary reciprocating internal combustion engines and combustion turbines used in the oil and natural gas industry are covered under separate NSPS specific to engines and turbines (40 CFR part 60, subparts IIII, JJJJ, GG, KKKK).

In addition to NSPS issued to regulate VOC emissions from the oil and gas industry, the EPA also published a CTG document that recommended the control of VOC emissions from equipment leaks from natural gas processing plants in 1983 (1983 CTG; 49 FR 4432; February 6, 1984).¹ This 2016 CTG is the only CTG document issued since 1983 for the oil and natural gas industry.

2.2 State and Local Regulations

Several states regulate VOC emissions from storage vessels in the oil and natural gas industry. There are also a few states (e.g., Colorado, Wyoming, and Montana) that have established specific permitting requirements or regulations that control VOC emissions from emission sources in the oil and natural gas industry (e.g., compressors, pneumatics, fugitive emission components):

- (1) The Colorado Department of Public Health and Environment, Air Quality Control Commission has developed emission regulations 3, 6, and 7 that apply to oil and natural gas industry emission sources in Colorado.
(<https://www.colorado.gov/pacific/cdphe/summary-oil-and-gas-emissions-requirements>.)
- (2) Montana requires oil and gas well facilities to control emissions from the time the well is completed until the source is registered or permitted (Registration of Air Contaminant

¹ U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, 27711. *Guideline Series. Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants*. December 1983. EPA-450/3-83-007.

Sources Rule, Rule 17.8.1711, Oil or Gas Well Facilities Emission Control Requirements). (<http://www.mtrules.org/gateway/ruleno.asp?RN=17%2E8%2E1711>.)

- (3) The Wyoming Department of Environmental Quality limits VOC emissions from existing sources in ozone nonattainment areas and has issued specific permitting guidance that apply to oil and natural gas facilities. (Chapter 6, Section 2 Permitting Guidance, last revised in September 2013).
- (4) The San Joaquin Valley Air Pollution Control District requires control of VOC emissions from several VOC oil and natural gas emission sources, including, but not limited to, (a) storage vessels, (b) crude oil production sumps, (c) components at light crude oil production facilities, natural gas production facilities and natural gas processing facilities, and (d) in-situ combustion well vents.

In some states, general permits have been developed for oil and natural gas facilities.

General permits are permits where all the terms and conditions of the permit are developed for a given industry and authorize the construction, modification, and/or operation of facilities that meet those terms and conditions. For example, West Virginia, Ohio, and Pennsylvania have developed General Air Permits for the oil and natural gas industry. The Pennsylvania Department of Environmental Protection has issued a General Permit, General Plan Approval and Permit Exemption 38 for natural gas dispensing facilities and oil and gas exploration, development, and production operations. Pennsylvania also applies conditions on flaring of emissions. Under the Permit 38 exemptions, there are criteria set out for the oil and natural gas industry that include unconditionally exempt and conditionally exempt criteria. Unconditionally exempt operations/equipment include conventional wells, conventional wellheads and associated equipment, well drilling, completion and work-over activities, and non-road engines. Unconventional wells, wellheads and associated equipment (including equipment components, storage vessels) are conditionally exempt. Conditions include compliance with 40 CFR part 60, subpart OOOO and Pennsylvania's General Permit 5 (GP-5) and a demonstration that the combined VOC emissions from all sources at a facility are less than 2.7 tons per year

(tpy) on a 12-month rolling basis. For oil and natural gas facilities that do not meet these conditions, a case-by-case plan approval is required.²

There may also be local permit requirements for control of VOC emissions from existing sources of VOC emissions in the oil and natural gas industry, such as those required by the Bay Area Air Quality Management District (BAAQMD) for pneumatic controllers. The BAAQMD requires that a permit to operate applicant provide the number of high-bleed and low-bleed pneumatic devices in their permit application. Facilities that use high-bleed devices might be required to provide device-specific bleed rates and supporting documentation for each high-bleed device. In cases where emissions are high from high-bleed devices, BAAQMD might require that the facility conduct fugitive monitoring and/or control requirements under conditions of their permit to operate³ on a case-by-case basis.

We conducted a search of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) and identified several draft and final permits that covered some of the sources evaluated for RACT in this CTG. The controls specified in these permits are similar to the control options evaluated in this CTG.⁴

We considered these existing state and local requirements limiting VOC emissions from the oil and natural gas industry in preparing this guideline.

2.3 Development of this CTG

As discussed in section 2.1 of this chapter, the NSPS established VOC emission standards for certain new and modified sources in the oil and gas industry. This CTG addresses existing sources of VOC emissions and provides recommendations for RACT for the oil and natural gas industry. We developed our RACT recommendations after reviewing the 1983 CTG document, the oil and natural gas NSPS, existing state and local VOC emission reduction approaches, and information on costs, emissions and available VOC emission control technologies. In April 2014, the EPA released five technical white papers on potentially significant sources of emissions in the oil and natural gas industry. The white papers focused on

² Pennsylvania Department of Environmental Protection. *Comparison of Air Emission Standards for the Oil & Natural Gas Industry* (Well Pad Operations, Natural Gas Compressor Stations, and Natural Gas Processing Facilities). May 23, 2014.

³ Cheng, Jimmy. *Permit Handbook. Chapter 3.5 Natural Gas Facilities and Crude Oil Facilities*. Bay Area Air Quality Management District. September 16, 2013.

⁴ RACT/BACT/LAER Clearinghouse website: <http://cfpub.epa.gov/RBLC/>.

technical issues covering emissions and mitigation techniques that target methane and VOC. We reviewed the white papers, along with the input we received from the peer reviewers and the public, when evaluating and recommending RACT.

This CTG reflects the evaluation of potential RACT options for emission sources that are regulated under the oil and natural gas NSPS. This CTG did not evaluate hydraulically fractured oil and natural gas well completions performed on existing wells because these operations are addressed in the NSPS.

Several of the technical support documents (TSDs) prepared in support of the NSPS actions for the oil and natural gas industry include data and analyses considered in developing RACT recommendations in this CTG. To the extent that the data and analyses are also relevant to control options for existing sources, they are referred to throughout this guidance document as follows:

- (1) The TSD for the 2011 NSPS proposal, published in July, 2011 is referred to as the “2011 NSPS TSD”.⁵
- (2) The supplemental TSD for the 2012 final NSPS standards, published in April, 2012, is referred to as the “2012 NSPS TSD” or “2012 NSPS STSD”.⁶
- (3) The TSD for the 2015 proposal NSPS standards, published August, 2015, is referred to as the “2015 NSPS TSD”.⁷
- (4) The TSD for the 2016 final NSPS standards, published in May, 2016, is referred to as the “2016 NSPS TSD”.⁸

Additionally, emission information and counts for various emission sources were summarized from facility-level data submitted to the Greenhouse Gas Reporting Program

⁵ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution – Background Technical Support Document for Proposed Standards*. July 2011. EPA-453/R-11002.

⁶ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. Docket ID No. EPA-HQ-OAR-2010-0505-4550.

⁷ U.S. Environmental Protection Agency. *Oil and Natural Gas Source Category: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Technical Support Document for the Proposed Amendments to the New Source Performance Standards*. August 2015. (See Docket No. EPA-HQ-OAR-2010-0505-5021; regulations.gov).

⁸ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources – Background Technical Support Document for the Final New Source Performance Standards*. May 2016.

(GHGRP)⁹ and data used to calculate national emissions in the Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHG Inventory).¹⁰ For the purposes of this document, these data sources are referred to as the “GHGRP” and the “GHG Inventory”. The most recent published data from the GHG Inventory when we prepared the draft CTG was for 2013, and was used for some of the analyses included in this document. Between the time we issued the draft CTG and the final CTG, GHGRP data was released that covers 2011 through 2014 and the most recent available GHG Inventory covers data from 1990 through 2014. These new activity data have been reviewed for this CTG and incorporated into our RACT analyses, as appropriate.

Most of the VOC emission estimates presented in this document are based on methane emissions data because we only had methane emissions information for the evaluated sources. We calculated VOC emissions using ratios of methane to VOC in the gas for the different segments of the industry. These ratios, and the procedures used to calculate them, are documented in a memorandum characterizing gas composition developed during the NSPS process.¹¹ Herein, we refer to this memorandum as the “2011 Gas Composition Memorandum”. Because methane emissions are the basis for most of our VOC emission estimates, in several instances where we provide VOC emissions per source/model plant, we also provide the methane emissions that are the basis for our VOC emission estimates.

The remainder of this document is divided into seven chapters and an appendix. Chapter three describes the oil and natural gas industry and a summary of our RACT recommendations presented in this CTG. Chapters four through nine describe the oil and natural gas emission sources that we evaluated for our RACT recommendations (i.e., storage vessels, compressors, pneumatic controllers, pneumatic pumps, equipment component leaks from natural gas processing plants, and fugitive emissions from well sites and gathering and boosting stations), available control and regulatory approaches (including existing federal, state and local requirements) and the potential emission reductions and costs associated with available control and regulatory approaches for a given emission source. The appendix provides example model

⁹ U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2014. (Reported Data: <http://www.epa.gov/ghgreporting/>). The Greenhouse Gas Reporting Program has particular definitions of “facility” for certain petroleum and natural gas systems industry segments. See 40 CFR 98.238.

¹⁰ U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990 - 2014*. Washington, DC. EPA 430-R-15-004. Available online at <https://www.epa.gov/ghgemissions/us-greenhouse-gas-inventory-report-1990-2014>.

¹¹ Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. *Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking*. July 2011. Docket ID No. EPA-HQ-OAR-2010-0505-0084.

rule language that can be used by air agencies as a starting point in the development of their SIP rules if they choose to adopt the recommended RACT presented in this document.

3.0 OVERVIEW OF THE OIL AND NATURAL GAS INDUSTRY AND SOURCES SELECTED FOR RACT RECOMMENDATIONS

Section 3.1 presents an overall description of the oil and natural gas industry and section 3.2 presents the VOC emission sources for which we are recommending RACT within the oil and natural gas industry. Table 3-1 provides a summary of recommendations for controlling VOC emissions from oil and natural gas industry emission sources.

3.1 Overview of the Oil and Natural Gas Industry

The oil and natural gas industry includes oil and natural gas operations involved in the extraction and production of crude oil and natural gas, as well as the processing, transmission, storage, and distribution of natural gas. For oil, the industry includes all operations from the well to the point of custody transfer at a petroleum refinery. For natural gas, the industry includes all operations from the well to the customer. For purposes of this document, the oil and natural gas operations are separated into four segments: (1) oil and natural gas production, (2) natural gas processing, (3) natural gas transmission and storage, and (4) natural gas distribution. We briefly discuss each of these segments below. For purposes of this CTG, oil and natural gas production includes only onshore operations.

Production operations include the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, and separation or treating of oil and/or natural gas (including condensate). Production components may include, but are not limited to, wells and related casing head, tubing head, and “Christmas tree” piping, as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices, and dehydrators. Production operations also include well drilling, completion, and recompletion processes, which include all the portable non-self-propelled apparatus associated with those operations. Production sites include not only the “pads” where the wells are located, but also include stand-alone sites where oil, condensate, produced water and gas from several wells may be separated, stored and treated. The production segment also includes the low-pressure, small diameter, gathering pipelines and related components that collect and transport the oil, natural gas, and other materials and wastes from the wells to the refineries or natural gas processing plants.

There are two basic types of wells: oil wells and natural gas wells. Oil wells can have “associated” natural gas that is separated and processed or the crude oil can be the only product processed. Crude oil production includes the well and extends to the point of custody transfer to the crude oil transmission pipeline. Once the crude oil is separated from water and other impurities, it is essentially ready to be transported to the refinery via truck, railcar, or pipeline. The oil refinery sector is considered separately from the oil and natural gas industry. Therefore, at the point of custody transfer at the refinery, the oil leaves the oil and natural gas sector and enters the petroleum refining sector.

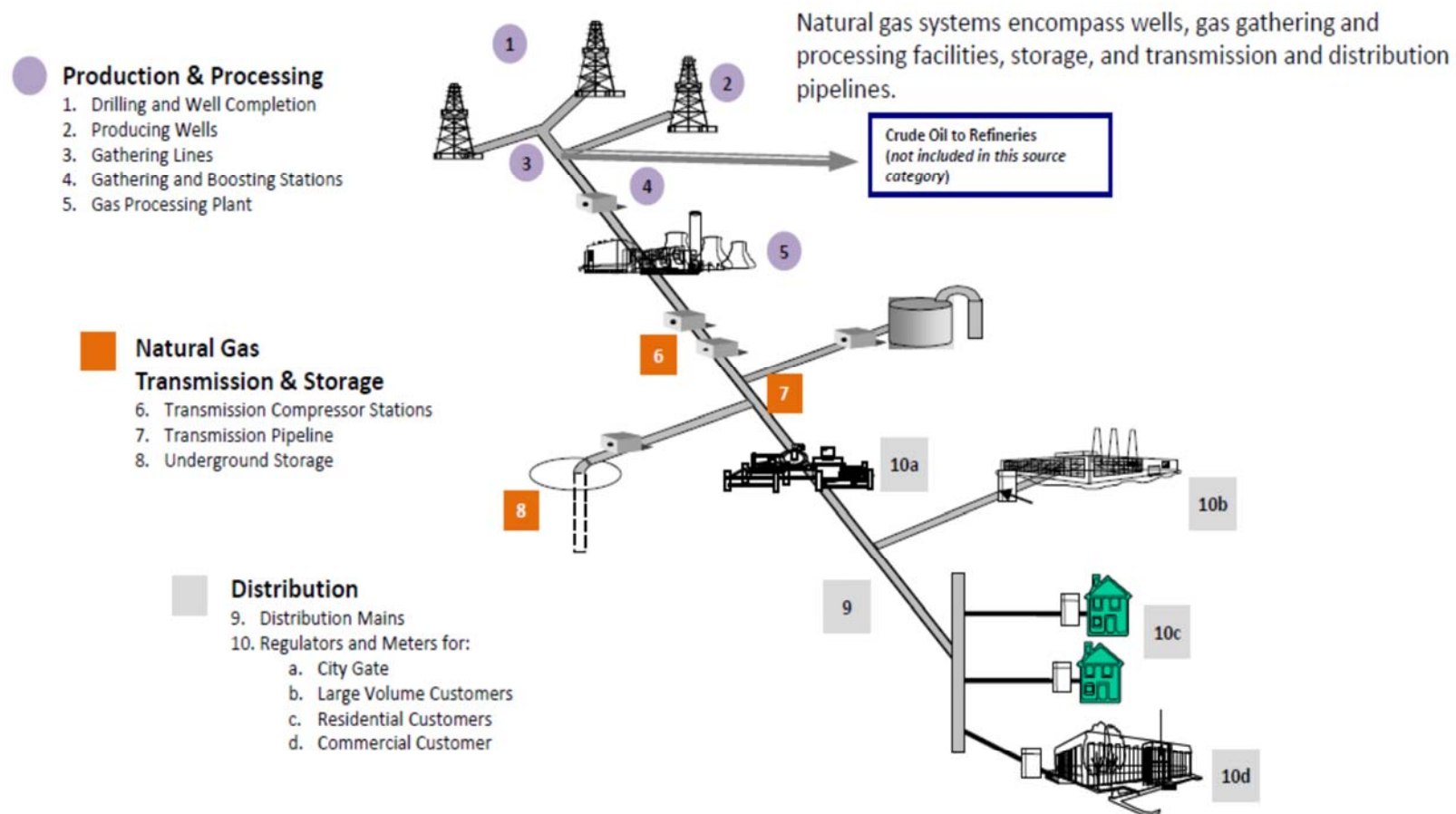
Natural gas is primarily made up of methane. It commonly exists in mixtures with other hydrocarbons. They are sold separately and have a variety of uses. The raw natural gas often contains water vapor, hydrogen sulfide (H₂S), carbon dioxide (CO₂), helium, nitrogen, and other compounds. Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produce “pipeline quality” dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover natural gas liquids (NGL) or other non-methane gases and liquids from a stream of produced natural gas through components performing one or more of the following processes: oil and condensate separation, water removal, separation of natural gas liquids, sulfur and CO₂ removal, fractionation of natural gas liquid, and other processes such as the capture of CO₂ separated from natural gas streams for delivery outside the facility.

The pipeline quality natural gas leaves the processing segment and enters the transmission and storage segment. Pipelines in the natural gas transmission and storage segment can be interstate pipelines that carry natural gas across state boundaries or intrastate pipelines, which transport the gas within a single state. While interstate pipelines may be of a larger diameter and operated at a higher pressure than intrastate pipelines, the basic components are the same. To ensure that the natural gas flowing through any pipeline remains pressurized, compression of the gas is required periodically along the pipeline. This is accomplished by compressor stations usually placed between 40 and 100 mile intervals along the pipeline. At a compressor station, the natural gas enters the station, where it is compressed by reciprocating or centrifugal compressors.

In addition to the pipelines and compressor stations, the natural gas transmission and storage segment includes aboveground and underground storage facilities. Underground natural gas storage includes subsurface storage, which typically consists of depleted gas or oil reservoirs and salt dome caverns used for storing natural gas. One purpose of this storage is for load balancing (equalizing the receipt and delivery of natural gas). At an underground storage site, there are typically other processes, including compression, dehydration, and flow measurement.

The distribution segment is the final step in delivering natural gas to customers. The natural gas enters the distribution segment from delivery points located on interstate and intrastate transmission pipelines to business and household customers. Natural gas distribution systems consist of thousands of miles of piping, including mains and service pipelines to the customers. Distribution systems sometimes have compressor stations, although they are considerably smaller than transmission compressor stations. Distribution systems include metering stations, which allow distribution companies to monitor the natural gas in the system. Essentially, these metering stations measure the flow of natural gas and allow distribution companies to track natural gas as it flows through the system.

Emissions can occur from a variety of processes and points throughout the oil and natural gas industry. Primarily, these emissions are organic compounds such as methane, ethane, VOC, and organic hazardous air pollutants (HAP). Figure 3-1 presents a schematic of oil and natural gas sector operations.



Source: Adapted from American Gas Association and EPA Natural Gas STAR Program

Figure 3-1. Oil and Natural Gas Sector Operations

3.2 Sources Selected For RACT Recommendations

This CTG covers select sources of VOC emissions in the onshore production and processing segments of the oil and natural gas industry (i.e., pneumatic controllers, pneumatic pumps, compressors, equipment leaks, fugitive emissions) and storage vessel VOC emissions in all segments (except distribution) of the oil and natural gas industry. These sources were selected for RACT recommendations because current information indicates that they are significant sources of VOC emissions. As mentioned in section 2.3, the VOC RACT recommendations contained in this document were made based on the review of the 1983 CTG document, the oil and natural gas NSPS, existing state and local VOC emission reduction approaches, and information on emissions, available VOC emission control technologies, and costs.

In considering costs, we compared control options and estimated costs and emission impacts of multiple emission reduction options under consideration. Recommendations are presented in this CTG for the subset of existing sources in the oil and natural gas industry where the application of controls is judged reasonable, given the availability of demonstrated control technologies, emission reductions that can be achieved, and the cost of control.

Table 3-1 presents a summary of the oil and natural gas emission sources and recommended RACT included in this CTG.

Table 3-1. Summary of the Oil and Natural Gas Industry Emission Sources and Recommended RACT Included in this CTG

Emission Source	Applicability	RACT Recommendations
Storage Vessels	Individual storage vessel with a potential to emit (PTE) greater than or equal to 6 tpy VOC.	95 percent reduction of VOC emissions from storage vessels. OR Maintain less than 4 tpy uncontrolled actual VOC emissions after having demonstrated that the uncontrolled actual VOC emissions have remained less than 4 tpy, as determined monthly, for 12 consecutive months.
	Individual continuous bleed, natural gas-driven pneumatic controller located at a natural gas processing plant.	Natural gas bleed rate of 0 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 0 scfh).
Pneumatic Controllers	Individual continuous bleed natural gas-driven pneumatic controller located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline.	Natural gas bleed rate less than or equal to 6 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh).
	Individual natural gas-driven diaphragm pump located at a natural gas processing plant.	Zero VOC emissions.
Pneumatic Pumps	Individual natural gas-driven diaphragm pump located at a well site.	Require routing of VOC emissions from the pneumatic pump to an existing onsite control device or process.
		Require 95 percent control unless the onsite existing control device or process cannot achieve 95 percent.
		If onsite existing device or process cannot achieve 95 percent, maintain documentation demonstrating the percent reduction the control device is designed to achieve.

Emission Source	Applicability	RACT Recommendations
		If there is no existing control device at the location of the pneumatic pump, maintain records that there is no existing control device onsite.
	Individual natural gas-driven diaphragm pump located at a well site that is in operation for any period of time each calendar day for less than a total of 90 days per calendar year.	RACT would not apply.
Compressors (Centrifugal and Reciprocating)	Individual reciprocating compressor located between the wellhead and point of custody transfer to the natural gas transmission and storage segment.	Reduce VOC emissions by replacing reciprocating compressor rod packing on or before 26,000 hours of operation or 36 months since the most recent rod packing replacement. Alternatively, route rod packing emissions to a process through a closed vent system under negative pressure.
	Individual reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site.	RACT would not apply.
	Individual centrifugal compressor using wet seals that is located between the wellhead and point of custody transfer to the natural gas transmission and storage segment.	Reduce VOC emissions from each centrifugal compressor wet seal fluid gassing system by 95 percent.
	Individual centrifugal compressor using wet seals located at a well site, or an adjacent well site and servicing more than one well site.	RACT would not apply.
	Individual centrifugal compressor using dry seals.	RACT would not apply.
Equipment Leaks	Equipment components in VOC service located at a natural gas processing plant.	Implement the 40 CFR part 60, subpart VVa leak detection and repair (LDAR) program for natural gas processing plants.
Fugitive Emissions	Individual well site with wells with a gas to oil ratio (GOR) greater than or equal to 300, that produce, on average, greater than 15 barrel equivalents per well per day.	Develop and implement a semiannual optical gas imaging (OGI) monitoring and repair plan that covers the collection of fugitive emissions components at well sites within a company defined area. Method 21 can be

Emission Source	Applicability	RACT Recommendations
		used as an alternative to OGI at a 500 ppm repair threshold level.
	Individual gathering and boosting station located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or point of custody transfer to an oil pipeline.	Develop and implement a quarterly OGI monitoring and repair plan that covers the collection of fugitive emissions components at gathering and boosting stations within a company defined area. Method 21 can be used as an alternative to OGI at a 500 ppm repair threshold.
	Individual well site with a GOR less than 300.	RACT would not apply.

4.0 STORAGE VESSELS

Storage vessels are significant sources of VOC emissions in the oil and natural gas industry. This chapter provides a description of the types of storage vessels present in the oil and natural gas industry, and provides VOC emission estimates for storage vessels, in terms of mass of emissions per throughput, for both crude oil and condensate storage vessels. This chapter also presents control techniques used to reduce VOC emissions from storage vessels, along with their costs and potential emission reductions. Finally, this chapter provides a discussion of our recommended RACT for storage vessels.

4.1 Applicability

For purposes of this CTG, the emissions and emission controls discussed herein would apply to a tank or other vessel in the oil and natural gas industry that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of non-earthen materials (such as wood, concrete, steel, fiberglass, or plastic) that provide structural support. The emissions and emission controls discussed herein would not apply to the following vessels:

- (1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships), and are intended to be located at a site for less than 180 consecutive days.
- (2) Process vessels such as surge control vessels, bottoms receivers, or knockout vessels.
- (3) Pressure vessels designed to operate in excess of 204.9 kilopascals (29.7 pounds per square inch) and without emissions to the atmosphere.¹²

4.2 Process Description and Emission Sources

4.2.1 Process Description

Storage vessels in the oil and natural gas industry are used to hold a variety of liquids including crude oil, condensates, produced water, etc. While still underground and at reservoir pressure, crude oil contains many lighter hydrocarbons in solution. When the oil is brought to the

¹² It is acknowledged that even pressure vessels designed to operate without emissions have a small potential for fugitive emissions at valves. Valves are threaded components that would be subject to leak detection and repair requirements.

surface, many of the dissolved lighter hydrocarbons (as well as water) are removed through a series of separators. Crude oil is passed through either a two-phase separator (where the associated gas is removed and any oil and water remain together) or a three-phase separator (where the associated gas is removed and the oil and water are also separated). The remaining oil is then directed to a storage vessel where it is stored for a period of time before being transported off-site. Much of the remaining hydrocarbon gases in the oil are released from the oil as vapors in the storage vessels. Storage vessels are typically installed with similar or identical vessels in a group, referred to in the industry as a tank battery.

Emissions of the hydrocarbons from storage vessels are a function of flash, breathing (or standing), and working losses. Flash losses occur when a liquid with entrained gases is transferred from a vessel with higher pressure to a vessel with lower pressure, thus allowing entrained gases or a portion of the liquid to vaporize or flash. In the oil and natural gas industry, flashing losses occur when crude oils or condensates flow into an atmospheric storage vessel from a processing vessel (e.g., a separator) operated at a higher pressure. Typically, the larger the pressure drop, the more flash emissions will occur in the storage vessel. The temperature of the liquid may also influence the amount of flash emissions. Breathing losses are the release of gas associated with temperature fluctuations and other equilibrium effects. Working losses occur when vapors are displaced due to the emptying and filling of storage vessels. The volume of gas vapor emitted from a storage vessel depends on many factors. Lighter crude oils flash more hydrocarbons than heavier crude oils. In storage vessels where the oil is frequently cycled and the overall throughput is high, working losses are higher. Additionally, the operating temperature and pressure of oil in the separator dumping into the storage vessel will affect the volume of flashed gases coming out of the oil.

The composition of the vapors from storage vessels varies, and the largest component is methane, but also may include ethane, butane, propane, and HAP such as benzene, toluene, ethylbenzene and xylenes (commonly referred to as BTEX), and n-hexane.

4.2.2 Emissions Data

4.2.2.1 *Summary of Major Studies and Emissions*

There are numerous studies and reports available that estimate storage vessel emissions. We consulted several of these studies and reports to evaluate the emissions and emission

reduction options for storage vessels. Table 4-1 presents a summary of the references for these reports, along with an indication of the type of information available in each reference.

Table 4-1. Major Studies Reviewed for Consideration of Emissions and Activity Data^{a,b}

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options ^e
VOC Emissions from Oil and Condensate Storage Tanks	Texas Environmental Research Consortium	2009	Regional	X	X
Upstream Oil and Gas Storage Tank Project Flash Emissions Models Evaluation – Final Report	Texas Commission on Environmental Quality	2009	Regional	X	
Initial Economic Impact Analysis for Proposed State Implementation Plan Revisions to the Air Quality Control Commission's Regulation Number 7	Colorado Air Quality Control Commission	2008	NA		X
E&P TANKS	API		National	X	
Inventory of U.S. Greenhouse Gas Emissions and Sinks ^c	EPA	Annual	National	X	
Greenhouse Gas Reporting Program (Annual Reporting: Current Data Available for 2011-2013) ^d	EPA	2014	Facility-Level	X	X

NA = Not Applicable.

^a U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket ID No. EPA-HQ-OAR-2010-0505-4550.

^b U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Technical Support*. July 2011. EPA-453/R-11-002.

^c U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. <https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html>.

^d U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2014.

^e An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

4.2.2.2 *Representative Storage Vessel Baseline Emissions*

Storage vessels vary in size and throughputs. In support of the 2013 NSPS Reconsideration,¹³ average storage vessel emissions, in terms of mass of emissions per throughput, were developed for both crude oil and condensate storage vessels.¹⁴ We also developed mass emissions per throughput estimates using the American Petroleum Institute's (API's) E&P TANKS program and more than 100 storage vessels across the country with varying characteristics.¹⁵ The VOC emissions per throughput estimates used for this analysis are:

- (1) Uncontrolled VOC Emissions from Crude Oil Storage Vessels = 0.214 tpy VOC/barrel per day (bbl/day); and
- (2) Uncontrolled VOC Emissions from Condensate Storage Vessels = 2.09 tpy VOC/bbl/day.

On a nationwide basis, there are a wide variety of storage vessel sizes, as well as rates of throughput for each tank. Emissions are directly related to the throughput of liquids for a given storage vessel; therefore, in support of the 2013 NSPS Reconsideration, we adopted production rate brackets developed by the U.S. Energy Information Administration (U.S. EIA) for our emission estimates. To estimate the emissions from an average storage vessel within each production rate bracket, we developed average production rates for each bracket. This average was calculated using the U.S. EIA published nationwide production per well per day for each production rate bracket from 2006 through 2009. Table 4-2 presents the average oil production and condensate production in barrels per well per day. For this analysis, we considered the liquid produced (as reported by the U.S. EIA) from oil wells to be crude oil and from gas wells to be condensate. Table 4-2 presents the average VOC emissions for each storage vessel within each production rate bracket calculated by applying the average production rate (bbl/day) to the VOC emissions per throughput estimates (tpy VOC/bbl/day).

¹³ 78 FR 58416, September 23, 2013. The EPA issued final updates to its 2012 VOC performance standards for storage tanks used in crude oil and natural gas production and transmission. The amendments reflected updated information that responded to issues raised in several petitions for reconsideration of the 2012 standards.

¹⁴ Brown, Heather, EC/R Incorporated. Memorandum prepared for Bruce Moore, EPA/OAQPS/SPPD/FIG. *Revised Analysis to Determine the Number of Storage Vessels Projected to be Subject to New Source Performance Standards for the Oil and Natural Gas Sector*. 2013.

¹⁵ American Petroleum Institute. *Production Tank Emissions Model. E&P Tank Version 2.0. A Program for Estimating Emissions from Hydrocarbon Production Tanks*. Software Number 4697. April 2000.

Table 4-2. Average Oil and Condensate Production and Storage Vessel Emissions per Production Rate Bracket¹⁶

Production Rate Bracket (BOE/day) ^a	Oil Wells		Gas Wells	
	Average Oil Production Rate per Oil Well (bbl/day) ^b	Crude Oil Storage Vessel VOC Emissions (tpy) ^c	Average Condensate Production Rate per Gas Well (bbl/day) ^b	Condensate Storage Vessel VOC Emissions (tpy) ^c
0-1	0.385	0.083	0.0183	0.038
1-2	1.34	0.287	0.0802	0.168
2-4	2.66	0.570	0.152	0.318
4-6	4.45	0.953	0.274	0.573
6-8	6.22	1.33	0.394	0.825
8-10	8.08	1.73	0.499	1.04
10-12	9.83	2.11	0.655	1.37
12-15	12.1	2.59	0.733	1.53
15-20	15.4	3.31	1.00	2.10
20-25	19.9	4.27	1.59	3.32
25-30	24.3	5.22	1.84	3.85
30-40	30.5	6.54	2.55	5.33
40-50	39.2	8.41	3.63	7.59
50-100	61.6	13.2	5.60	11.7
100-200	120	25.6	12.1	25.4
200-400	238	51.0	23.8	49.8
400-800	456	97.7	44.1	92.3
800-1,600	914	196	67.9	142
1,600-3,200	1,692	363	148	311
3,200-6,400	3,353	719	234	490
6,400-12,800	6,825	1,464	891	1,864
> 12,800 ^d	0	0	0	0

Minor discrepancies may be due to rounding.

^a BOE=Barrels of Oil Equivalent

^b Oil and condensate production rates published by U.S. EIA. "United States Total Distribution of Wells by Production Rate Bracket."

^c Oil storage vessel VOC emission factor = 0.214 tpy VOC/bbl/day. Condensate storage vessel VOC emission factor = 2.09 tpy/bbl/day.

^d There were no new oil and gas well completions in 2009 for this rate category. Therefore, average production rates were set to zero.

¹⁶ Brown, Heather, EC/R Incorporated. Memorandum prepared for Bruce Moore, EPA/OAQPS/SPPD/FIG. *Revised Analysis to Determine the Number of Storage Vessels Projected to be Subject to New Source Performance Standards for the Oil and Natural Gas Sector*. 2013.

4.3 Available Controls and Regulatory Approaches

In analyzing available controls for storage vessels, we reviewed information obtained in support of the 2012 NSPS¹⁷ and the 2013 NSPS Reconsideration actions, control techniques identified in the Natural Gas STAR program, and existing state regulations that require control of VOC emissions from storage vessels in the oil and natural gas industry. Section 4.3.1 presents a non-exhaustive discussion of available VOC emission control methods for storage vessels. Section 4.3.2 includes a summary of the federal, state, and local regulatory approaches that control VOC emissions from crude oil and condensate storage vessels.

4.3.1 Available VOC Emission Control Options

The options generally used as the primary means to limit the amount of VOC vented are to: (1) route emissions from the storage vessel through an enclosed system to a process where emissions are recycled, recovered, or reused in the process – “route to a process” (e.g., by installing a vapor recovery unit (VRU) that recovers vapors from the storage vessel) for reuse in the process or for beneficial use of the gas onsite and/or (2) route emissions from the storage vessel to a combustion device. While EPA explored these options within the document, there may be other emission controls that sources may wish to employ to ensure continuous compliance with EPA’s RACT recommendation. Regardless of the type of emission control method that a source may choose to utilize, the recommended RACT level of control explained more fully below is meant to apply at all times. One of the clear advantages the first option has over the second option is that it results in a cost savings associated with the recycled, recovered and reused natural gas and other hydrocarbon vapor, rather than the loss and destruction of the natural gas and vapor by combustion. Combustion and partial combustion of organic pollutants also creates secondary pollutants including nitrogen oxides, carbon monoxide, sulfur oxides, carbon dioxide and smoke/particulates. These emission control methods are described below along with their emission reduction control effectiveness as they apply to storage vessels in the industry and the potential costs associated with their installation and operation.

¹⁷ *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standard for Hazardous Air Pollutants Reviews. Final Rule.* 77 FR 49490, August 16, 2012.

4.3.1.1 *Routing Emissions to a Process via a Vapor Recovery Unit (VRU)*

Description

One option for controlling storage vessel emissions is to route vapors from the storage vessel back to the inlet line of a separator, to a sales gas line, or to some other line carrying hydrocarbon fluids for beneficial use, such as use as a fuel. Where a compressor is used to boost the recovered vapors into the line, this is often referred to as a VRU.¹⁸ Typically with a VRU, hydrocarbon vapors are drawn out of the storage vessel under low pressure and are piped to a separator, or suction scrubber, to collect any condensed liquids, which are usually recycled back to the storage vessel. Vapors from the separator flow through a compressor that provides the low-pressure suction for the VRU system where the recovered hydrocarbons can be transported to various places, including a sales line and/or for use onsite.

Types of VRUs include conventional VRUs and venturi ejector vapor recovery units (EVRUTM) or vapor jet systems.¹⁹ Decisions on the type of VRU to use are based on the applicability needs (e.g., an EVRUTM is recommended where there is a high-pressure gas compressor with excess capacity and a vapor jet VRU is suggested where there is produced water, less than 75 million cubic feet (MMcf)/day gas and discharge pressures below 40 pounds per square inch gauge (psig)). The reliability and integrity of the compressor and suction scrubber and integrity of the lines that connect the tank to the compressor will affect the effectiveness of the VRU system to collect and recycle vapors.²⁰

A conventional VRU is equipped with a control pilot to shut down the compressor and permit the back flow of vapors into the tank in order to prevent the creation of a vacuum in the top of a tank when liquid is withdrawn and the liquid level drops. Vapors are then either sent to the pipeline for sale or used as onsite fuel. Figure 4.1 presents a diagram of a conventional VRU installed on a single crude oil storage vessel (multiple tank installations are also common).²¹

¹⁸ American Petroleum Institute. Letter to Bruce Moore, SPPD/OAQPS/EPA from M. Todd, API. *Re: Oil and Natural Gas Sector Consolidated Rulemaking*. Docket ID No. EPA-HQ-OAR-2010-0505.

¹⁹ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Installing Vapor Recovery Units*. Natural Gas STAR Program. Source Reduction Training to Interstate Oil and Gas Compact Commission Presentation. February 27, 2009.

²⁰ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Installing Vapor Recovery Units on Storage Tanks*. Natural Gas STAR Program. October 2006.

²¹ Ibid.

Conventional VRU

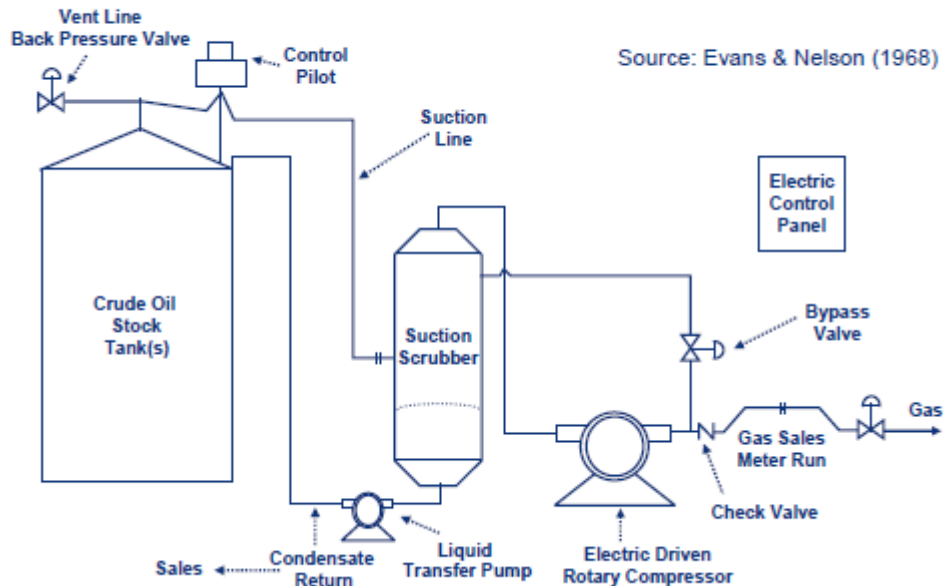


Figure 4-1. Conventional Vapor Recovery System

Control Effectiveness

Vapor recovery units have been shown to reduce VOC emissions from storage vessels by over 95 percent.²² When operating properly, VRUs generally approach 100 percent efficiency. We recognize that VRUs may not continuously meet this efficiency in practice. Therefore, our analysis assumes a 95 percent reduction in VOC emissions for a VRU. A VRU recovers hydrocarbon vapors that potentially can be used as supplemental burner fuel, or the vapors can be condensed and collected as condensate that can be sold. If natural gas is recovered, it can be sold as well, as long as a gathering line is available to convey the recovered salable gas product to market or to further processing. A VRU cannot be used in all instances. Conditions that affect the feasibility of the use of a VRU include: the availability of electrical service sufficient to power the compressor; fluctuations in vapor loading caused by surges in throughput and flash emissions from the storage vessel; potential for drawing air into condensate storage vessels causing an explosion hazard; and lack of appropriate destination or use for the vapor recovered.

²² Ibid.

Cost Impacts

Cost data for a VRU obtained from an initial economic impact analysis prepared for proposed state-only revisions to a Colorado regulation are presented here.²³ We assumed cost information contained in the Colorado economic impact analysis to be given in 2012 dollars. According to the Colorado economic impact analysis, the cost of a VRU was estimated to be \$90,000. Including costs associated with freight and design, and the cost of VRU installation, we estimated costs to be \$102,802 (\$90,000 plus \$12,802). We also added an estimated storage vessel retrofit cost of \$68,736 assuming that the cost of retrofitting an existing storage vessel was 75 percent of the purchased equipment cost (i.e., VRU capital cost and freight and design cost).²⁴ Based on these costs, we estimated the total capital investment of the VRU to be \$171,538. These cost data are presented in Table 4-3. We estimated total annual costs using 2012 dollars to be \$28,230 per year without recovered natural gas savings. The uncontrolled emissions from a storage vessel are largely dependent on the bbl/year throughput (see Table 4-2), which greatly influences both the controlled emissions and the cost of control per ton of VOC reduced. Costs may vary due to VRU design capacity, system configuration, and individual site needs and recovery opportunities.

In order to assess the cost of control of a VRU for uncontrolled storage vessels that emit differing emissions, we evaluated the cost of routing VOC emissions from an existing uncontrolled storage vessel to a VRU for a storage vessel that emits 2 tpy, 4 tpy, 6 tpy, 8 tpy, 10 tpy, 12 tpy, and 25 tpy. We estimated the cost of control without savings by dividing the total annual costs without savings by the tpy reduced assuming 95 percent control. The cost of control with savings is calculated by assuming a 95 percent reduction of VOC emissions by the VRU and converting the reduced VOC emissions to natural gas savings. Table 4-4 presents the estimated natural gas savings and the VOC cost per ton of VOC reduced with and without savings.

²³ Initial Economic Impact Analysis for Proposed Revisions to the Colorado Air Quality Control Commission Regulation Number 7, *Emissions of Volatile Organic Compounds*. November 15, 2013.

²⁴ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Installing Vapor Recovery Units on Storage Tanks*. Natural Gas STAR Program. October 2006.

Table 4-3. Total Capital Investment and Total Annual Costs of a Vapor Recovery Unit System

Cost Item^a	Cost (\$2012)
<i>Capital Cost Items</i>	
VRU ^a	\$90,000
Freight and Design ^a	\$1,648
VRU Installation ^a	\$11,154
Storage Vessel Retrofit ^b	\$68,736
Total Capital Investment	\$171,538
<i>Annual Cost Items</i>	
Maintenance	\$9,396
Capital Recovery (7 percent interest, 15 year equipment life) (\$/yr)	\$18,834
Total Annual Costs w/o Savings (\$/yr)	\$28,230

^a Cost data from the Initial Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7, Submitted with Request for Hearing Documents on November 15, 2013.

^b Assumes the storage vessel retrofit cost is 75 percent of the purchased equipment price (assumed to include vent system and piping to route emissions to the control device). Retrofit assumption from Exhibit 6 of the EPA Natural Gas Star Lessons Learned, *Installing Vapor Recovery Units on Storage Tanks*. October 2006.

Table 4-4. Cost of Routing Emissions from an Existing Uncontrolled Storage Vessel to a VRU (\$/ton of VOC Reduced)

Uncontrolled Storage Vessel Emissions (tpy)	Cost per Ton of VOC Reduced (\$2012)		
	Without Savings	Natural Gas Savings (Mscf/yr)^a	With Savings^b
2	\$14,858	59	\$14,734
4	\$7,429	118	\$7,305
6	\$4,953	177	\$4,828
8	\$3,714	236	\$3,590
10	\$2,972	295	\$2,847
12	\$2,476	353	\$2,352
25	\$1,189	736	\$1,065

^a The natural gas savings was calculated by assuming 95 percent VOC recovery and 31 Mscf/yr natural gas savings per ton of VOC recovered.

^b Assumes a natural gas price of \$4.00 per Mcf.

Additionally, if a VRU is used to control VOC emissions from multiple storage vessels, the VOC emissions cost of control would be reduced because the cost for the additional storage vessel(s) would only include the storage vessel retrofit costs, and the overall VOC emission reductions would increase.

4.3.1.2 *Routing Emissions to a Combustion Device*

Description and Control Effectiveness

Combustors (e.g., enclosed combustion devices, thermal oxidizers and flares that use a high-temperature oxidation process) are also used to control emissions from storage vessels. Combustors are used to control VOC in many industrial settings, since the combustor can normally handle fluctuations in concentration, flow rate, heating value, and inert species content.²⁵ For this analysis, we assumed that the types of combustors installed in the oil and natural gas industry can achieve at least a 95 percent control efficiency on a continuing basis.²⁶ We note that combustion devices can be designed to meet 98 percent control efficiencies, and can control, on average, emissions by 98 percent or more in practice when properly operated.²⁷ We also recognize that combustion devices that are designed to meet a 98 percent control efficiency may not continuously meet this efficiency in practice, due to factors such as variability of field conditions.

A typical combustor used to control emissions from storage vessels in the oil and natural gas industry is an enclosed combustion system. The basic components of an enclosed combustion system include (1) piping for collecting emission source gases, (2) a single- or multiple-burner unit, (3) a stack enclosure, (4) a pilot flame to ignite the mixture of emission source gas and air and (5) combustor fuel/piping (as necessary). Figure 4-2 presents a schematic of a typical dual-burner enclosed combustion system.

²⁵ U.S. Environmental Protection Agency. AP 42, Fifth Edition, Volume I, *Chapter 13.5 Industrial Flares*. Office of Air Quality Planning & Standards. 1991.

²⁶ U.S. Environmental Protection Agency. *Air Pollution Control Technology Fact Sheet: FLARE*. Clean Air Technology Center.

²⁷ The EPA has currently reviewed performance tests submitted for 19 different makes/models of combustor control devices and confirmed that they meet the performance requirements in NSPS subpart OOOO and NESHAP subparts HH and HHH. All reported control efficiencies were above 99.9 percent at tested conditions. The EPA notes that the control efficiency achieved in the field is likely to be lower than the control efficiency achieved at a bench test site under controlled conditions, but we believe that these units should have no problem meeting 95 percent control continuously and 98 percent control on average when designed and properly operated to meet 98 percent control.

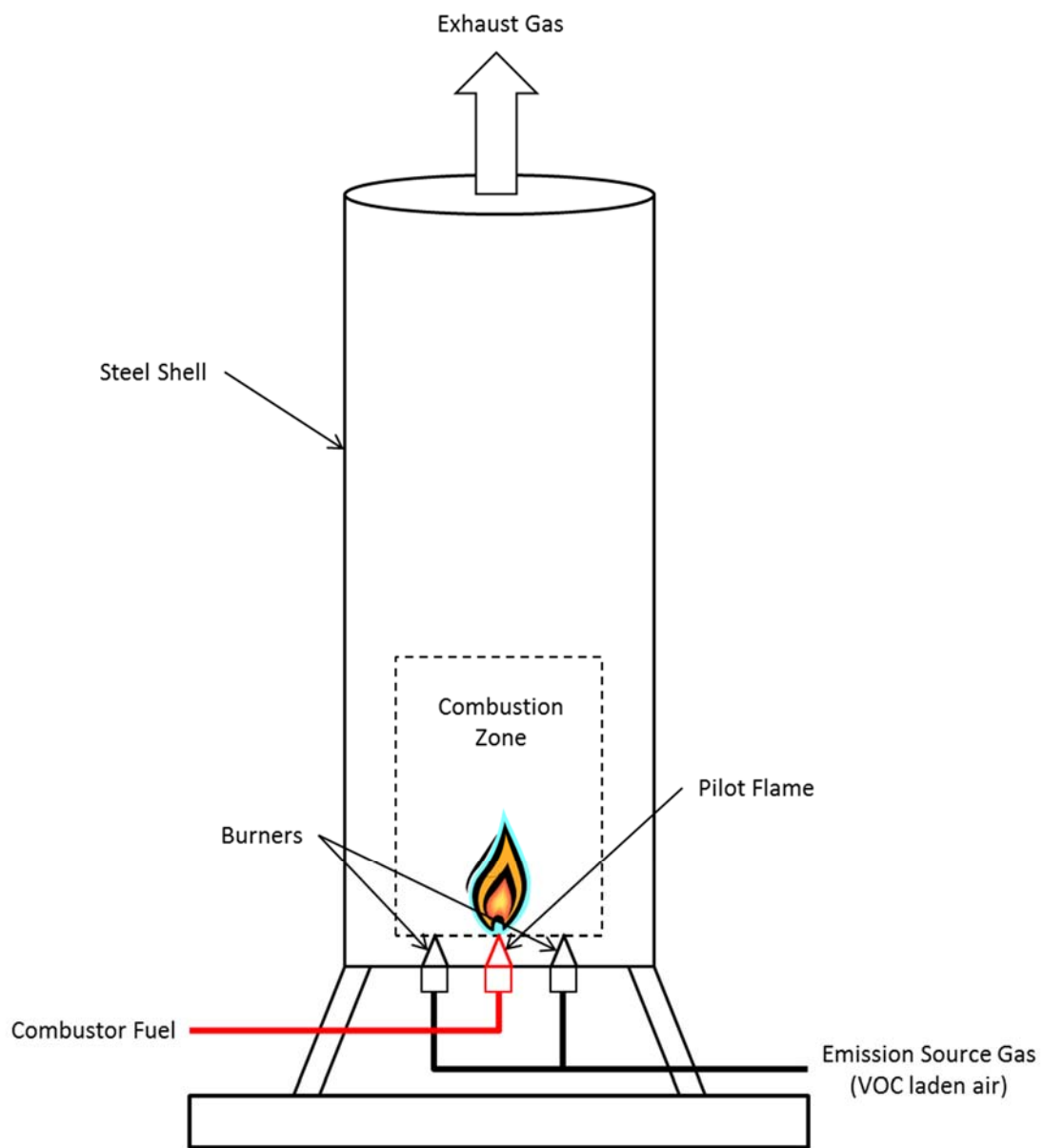


Figure 4-2. Schematic of a Typical Enclosed Combustion System

Thermal oxidizers, also referred to as direct flame incinerators, thermal incinerators, or afterburners, could also be used to control VOC emissions. Similar to a basic enclosed combustion device, a thermal oxidizer uses burner fuel to maintain a high temperature (typically 800-850°C) within a combustion chamber. The VOC laden emission source gas is injected into the combustion chamber where it is oxidized (burned), and then the combustion products are exhausted to the atmosphere. Figure 4-3 provides a basic schematic of a thermal oxidizer.²⁸

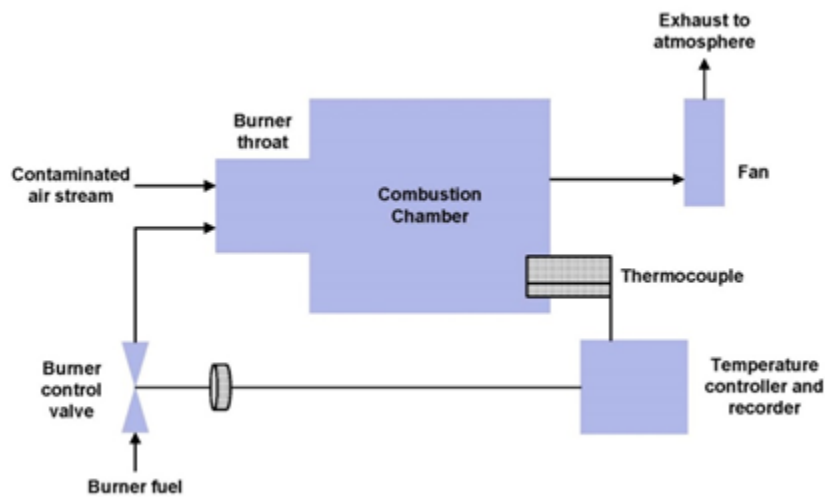


Figure 4-3. Basic Schematic of a Thermal Oxidizer

Cost Impacts

For combustion devices, we obtained cost data from the initial economic impact analysis prepared for state-only revisions to the Colorado regulation.²⁹ In addition to these cost data, we added line items for operating labor, a surveillance system and data management. This is consistent with the guidelines outlined in the EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (OCCM) for combustion devices and the cost analysis prepared for the 2012 NSPS.^{30,31} However, OCCM guidelines specify 630 operating labor hours

²⁸ U.S. Environmental Protection Agency. Technology Transfer Network. Clearinghouse for Inventories and Emission Factors. *Thermal Oxidizer*. Website: <https://cfpub.epa.gov/oarweb/mkb/contechnique.cfm?ControllD=17>.

²⁹ Initial Economic Impact Analysis for Proposed Revisions to the Colorado Air Quality Control Commission Regulation Number 7, *Emissions of Volatile Organic Compounds*. November 15, 2013.

³⁰ *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standard for Hazardous Air Pollutants Reviews. Final Rule*. 77 FR 49490, August 16, 2012.

³¹ U.S. Environmental Protection Agency. *OAQPS Control Cost Manual: Sixth Edition* (EPA 452/B-02-001). Research Triangle Park, NC.

per year for a combustion device, which we believe is unreasonable because many of these sites are unmanned and would most likely be operated remotely. Therefore, we assumed that the operating labor would be more similar to that estimated for a condenser in the OCCM, 130 hours per year. We estimated a total capital investment of \$100,986 and total annual costs of \$25,194 per year. The total capital investment cost includes a storage vessel retrofit cost of \$68,736 (as discussed previously for VRUs) to accommodate the use of a combustion device. These cost data are presented in Table 4-5.

Table 4-5. Total Capital Investment and Total Annual Costs of a Combustor³²

Cost Item^a	Cost (\$2012)
<i>Capital Cost Items</i>	
Combustor ^a	\$18,169
Freight and Design ^a	\$1,648
Auto Ignitor ^a	\$1,648
Surveillance System ^{b,c,d}	\$3,805
Combustor Installation ^a	\$6,980
Storage Vessel Retrofit ^e	\$68,736
Total Capital Investment	\$100,986
<i>Annual Cost Items</i>	
Operating Labor ^f	\$5,155
Maintenance Labor ^f	\$4,160
Non-Labor Maintenance ^a	\$2,197
Pilot Fuel	\$1,537
Data Management ^c	\$1,057
Capital Recovery (7 percent interest, 15 year equipment life) (\$/yr)	\$11,088
Total Annual Cost (\$/yr)	\$25,194

^a Cost data from Initial Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7, Submitted with Request for Hearing Documents on November 15, 2013.

^b Surveillance system identifies when pilot is not lit and attempts to relight it, documents the duration of time when the pilot is not lit, and notifies and operator that repairs are necessary.

³² U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

^c U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket ID No. EPA-HQ-OAR-2010-0505-4550.

^d Cost obtained from 2012 NSPS TSD and escalated using the change in GDP: Implicit Price Deflator from 2008 to 2012 (percent) (which was 5.69 percent). Source: FRED GDP: Implicit Price Deflator from Jan 2008 to Jan 2012 (<http://research.stlouisfed.org/fred2/series/GDPDEF/#>).

^e Retrofit cost obtained from Storage Vessel Retrofit in Table 4-3 (assumed to include vent system and piping to route emissions to the control device).

^f Operating labor consists of labor resources for technical operation of device (130 hr/yr) and supervisory labor (15 percent of technical labor hours). Maintenance labor hours are assumed to be the same as operating labor (130 hr/yr). Labor rates are \$32.00/hr (for technical and maintenance labor) and \$51.03 (supervisory labor) and were obtained from the U.S. Department of Labor, Bureau of Labor Statistics, Employer Costs for Employee Compensation, December 2012. Labor rates account for total compensation (wages/salaries, insurance, paid leave, retirement and savings, supplemental pay and legally required benefits).

As noted previously, storage vessels vary in size and throughputs and the uncontrolled emissions from a storage vessel are largely dependent on the bbl/year throughput (see Table 4-2), which greatly influences both the controlled emissions and cost of control. In order to assess the cost of control of combustion for uncontrolled storage vessels that emit differing emissions, we evaluated the costs of routing VOC emissions from an existing storage vessel to a combustion device for an existing uncontrolled storage vessel that emits 2 tpy, 4 tpy, 6 tpy, 8 tpy, 10 tpy, 12 tpy and 25 tpy. We estimated the cost of control without savings by dividing the total annual costs without savings by the tpy reduced assuming 95 percent control. Table 4-6 presents these costs. The VOC emissions cost of control per ton of VOC reduced would be less if a combustion device is used to control uncontrolled VOC emissions from multiple storage vessels because the cost for the additional storage vessel(s) would only include storage vessel retrofit costs, and the overall VOC emission reductions would increase.

Table 4-6. Cost of Routing Emissions from an Existing Uncontrolled Storage Vessel to a Combustion Device (\$/ton of VOC Reduced)

Uncontrolled Storage Vessel Emissions (tpy)	Cost per Ton of VOC Reduced (\$2012)
2	\$13,260
4	\$6,630
6	\$4,420
8	\$3,315

Uncontrolled Storage Vessel Emissions (tpy)	Cost per Ton of VOC Reduced (\$2012)
10	\$2,652
12	\$2,411
25	\$2,210

4.3.1.3 *Routing Emissions to a VRU with a Combustion Device as Backup*

Industry practice also includes the primary operation of a VRU and secondary operation of a combustion device during VRU maintenance and other times requiring VRU downtime. Using the costs for a VRU and combustion device presented in sections 4.3.1.1 and 4.3.1.2, and assuming the VRU is operated 95 percent of the year and a combustion device is operated 5 percent of the year, we estimated total annual costs using 2012 dollars to be \$32,006 per year without recovered natural gas savings. As stated previously, the uncontrolled emissions from a storage vessel are largely dependent on the bbl/year throughput (see Table 4-2), which greatly influences both the controlled emissions and the cost of control per ton of VOC reduced. Costs may vary due to VRU design capacity, system configuration, and individual site needs and recovery opportunities, as well as the percent of time that a VRU is down during the year where emissions are routed to a combustion device. In order to assess the cost of control of a VRU with the use of a combustion device during downtime for uncontrolled storage vessels that emit differing emissions, we evaluated the costs of routing VOC emissions from an existing storage vessel to a VRU/combustion device for an existing uncontrolled storage vessel that emits 2 tpy, 4 tpy, 6 tpy, 8 tpy, 10 tpy, 12 tpy and 25 tpy. We estimated the cost of control without savings by dividing the total annual costs without savings by the tpy reduced assuming 95 percent control. The cost of control with savings is calculated by assuming a 95 percent reduction of VOC emissions by the VRU (used 95 percent of the year) and converting the reduced VOC emissions to natural gas savings. Table 4-7 presents these costs. The VOC emissions cost of control per ton of VOC reduced would be less if a VRU/combustion device is used to control uncontrolled VOC emissions from multiple storage vessels because the cost for the additional storage vessel(s) would only include storage vessel retrofit costs, and the overall VOC emission reductions would increase.

Table 4-7. Cost of Routing Emissions from an Existing Uncontrolled Storage Vessel to a VRU/Combustion Device (\$/ton of VOC Reduced)

Uncontrolled Storage Vessel Emissions (tpy)	Cost per Ton of VOC Reduced (\$2012)		
	Without Savings	Natural Gas Savings (Mscf/yr) ^a	With Savings ^b
2	\$16,845	56	\$16,728
4	\$8,423	112	\$8,305
6	\$5,615	168	\$5,497
8	\$4,211	224	\$4,094
10	\$3,369	280	\$3,251
12	\$2,808	336	\$2,690
25	\$1,348	699	\$1,230

^a The natural gas savings was calculated by assuming 95 percent VOC recovery and 31 Mscf/yr natural gas savings per ton of VOC recovered.

^b Assumes a natural gas price of \$4.00 per Mcf.

4.3.2 Existing Federal, State and Local Regulations

4.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

Under the 2012 NSPS and 2013 NSPS Reconsideration, new or modified storage vessels with PTE VOC emissions of 6 tpy or more must reduce VOC emissions by at least 95 percent, or demonstrate emissions from a storage vessel have dropped to less than 4 tpy of VOC without emission controls for 12 consecutive months.

4.3.2.2 State and Local Regulations that Specifically Require Control of VOC Emissions³³

States may have permitting restrictions on VOC emissions that may apply to an emissions source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met, and how the source must be operated. To ensure that sources

³³ Brown, Heather, EC/R Incorporated. Memorandum prepared for Bruce Moore, EPA/OAQPS/SPPD/FIG. *Revised Analysis to Determine the Number of Storage Vessels Projected to be Subject to New Source Performance Standards for the Oil and Natural Gas Sector*. 2013.

follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

The environmental regulations in nine of the top oil and natural gas producing states (sometimes with varying local ozone nonattainment area/concentrated area development requirements) (see Table 4-8) require the control of VOC emissions from storage vessels in the oil and natural gas industry. These states include California, Colorado, Kansas, Louisiana, Montana, North Dakota, Oklahoma, Texas, and Wyoming. All except Wyoming require 95 percent emission control with the application of a VRU or combustion (Wyoming requires 98 percent control of emissions using a VRU or combustion).

Existing state regulations that apply to storage vessels in the oil and natural gas industry apply to all storage vessels in a tank battery, or include an applicability threshold based on (1) capacity, (2) the vapor pressure of liquids contained in a storage vessel of a specified capacity, and (3) the PTE of an individual storage vessel. Table 4-8 presents a brief summary of the storage vessel emission control applicability cutoffs in regulations from these nine states. Four states (Colorado, Montana, Texas, and Wyoming) have applicability thresholds in terms of VOC emissions. The remaining five states have storage vessel regulations that are in terms of tank characteristics, such as vapor pressure, tank size, or tank contents. Equivalency of applicability thresholds based on tank and stored liquid characteristics and applicability thresholds based on VOC emissions cannot be determined. We analyzed the varying state VOC emission thresholds (based on a range of 2 tpy to 25 tpy) as part of our cost of control analysis for VRUs and combustion devices in section 4.3.1 of this chapter.

Table 4-8. Summary of Storage Vessel Applicability Thresholds from Nine States

State/Local Authority	Applicability Threshold
Texas	Applies to storage vessels with VOC emissions greater than 25 tpy.
California Bay Area AQMD	Applies to storage vessels with capacity greater than 264 gallons.
California Feather River AQMD	Applies to storage vessels with capacity greater than 39,630 gallons.
California Monterey Bay Unified APCD	Applies to storage vessels with capacity greater than 39,630 gallons.

State/Local Authority	Applicability Threshold
California Sacramento Metropolitan AQMD	Applies to storage vessels with capacity greater than 40,000 gallons.
California San Joaquin Valley Unified APCD	Applies to storage vessels with capacity greater than 1,100 gallons.
California Santa Barbara County APCD	Applies to all storage vessels in tank battery (including wash tanks, produced water tanks, and wastewater tanks).
California South Coast AQMD	Applies to storage vessels with capacity greater than 39,630 gallons with a true vapor pressure of 0.5 psia or greater and storage vessels with a capacity greater than 19,815 gallons with a true vapor pressure of 1.5 psia or greater.
California Ventura County APCD	Applies to all storage vessels. Requirements depend on gallon capacity and true vapor pressure of material contained in vessel.
California Yolo-Solano AQMD	Applies to storage vessels with capacity greater than 40,000 gallons.
North Dakota	NDAC 33-15-07: submerged filling requirements to control VOC for tanks >1,000 gallons.
Federal Implementation Plan (FIP): Fort Berthold Indian Reservation	Applies to all storage vessels (except those covered by NSPS subpart OOOO). There is no minimum threshold under the final FIP.
Louisiana	Applies to storage vessels more than 250 gallons up to 40,000 gallons with a maximum true vapor pressure of 1.5 psia or greater.
Oklahoma	Applies to storage vessels with capacity greater than 40,000 gallons (in ozone nonattainment areas).
Wyoming – Statewide	Applies to storage vessels with greater than or equal to 10 tpy VOC within 60 days of startup/modification.
Wyoming – Concentrated Development Area	Applies to storage vessels with greater than or equal to 8 tpy VOC within 60 days of startup/modification.
Kansas	Permanent fixed roof storage tanks >40,000 gallons and external floating roof storage tanks.
Colorado	Condensate tanks with uncontrolled VOC emissions > 20 tpy (2 tpy located at gas processing plants in ozone non-attainment areas).

State/Local Authority	Applicability Threshold
Montana	Applies to oil or condensate storage tanks with a PTE greater than 15 tpy VOC.

4.4 Recommended RACT Level of Control

As discussed in section 4.3.2 of this chapter, existing federal and state and local regulations already require the reduction of VOC emissions from storage vessels in the oil and natural gas industry at or greater than 95 percent. Further, we note that combustion devices can be designed to meet 98 percent control efficiencies and can control, on average, emissions by 98 percent or more in practice when properly operated.³⁴ We also recognize that combustion devices designed to meet 98 percent control efficiency may not continuously meet this efficiency in practice, due to factors such as the variability of field conditions. Therefore, the recommendations specify that devices should be required to continuously meet at least 95 percent VOC control efficiency. In light of the above considerations, a continuous 95 percent reduction of VOC emissions from storage vessels in the oil and natural gas industry is a reasonable recommended RACT level of control.

Although sources may have a choice on how they meet the recommended RACT level of control, if air agencies choose to adopt the recommended RACT contained in this CTG, the technologies that may be used to meet the recommended RACT level of control for oil and natural gas industry storage vessels are capturing and routing emissions to the process via a VRU and/or routing emissions to a combustion device.

As discussed in section 4.2.2 of this chapter, the VOC emissions from storage vessels vary significantly, depending on the rate of liquid entering and passing through the vessel (i.e., its throughput), the pressure of the liquid as it enters the atmospheric pressure storage vessel, the liquid's volatility, and temperature of the liquid. Some storage vessels have negligible emissions, such as those with very little throughput and/or handling heavy liquids entering at atmospheric

³⁴ The EPA has currently reviewed performance tests submitted for 19 different makes/models of combustor control devices and confirmed they meet the performance requirements in NSPS subpart OOOO and NESHAP subparts HH and HHH. All reported control efficiencies were above 99.9 percent at tested conditions. EPA notes that the control efficiency achieved in the field is likely to be lower than the control efficiency achieved at a bench test site under controlled conditions, but we believe that these units should have no problem meeting 95 percent control continuously and 98 percent control on average when designed and properly operated to meet 98 percent control.

pressure where it would not be cost-effective to require emission control requirements. Existing state regulations that apply to storage vessels in the oil and natural gas industry apply to all storage vessels in a tank battery, or include an applicability threshold based on (1) capacity, (2) the vapor pressure of liquids contained in a storage vessel of a specified capacity, and (3) the PTE of an individual storage vessel. Based on information gathered under the 2012 NSPS,³⁵ throughput and capacity of a storage vessel is not always the best indicator of a storage vessel's emissions, and we believe that the PTE of an individual storage vessel is preferable to use as an applicability threshold for storage vessels.

Based on our analyses conducted in support of the 2012 NSPS, 6 tpy was determined to be the applicability threshold for requiring 95 percent control of VOC emissions from new storage vessels (estimated to cost, on average, approximately \$3,400 per ton of VOC reduced). Our analyses conducted for our RACT recommendation also found 6 tpy to be the applicability threshold for requiring 95 percent control of VOC emissions from existing storage vessels (estimated to cost, on average, between \$4,400 and \$5,000 per ton of VOC reduced). Based on these analyses, we recommend that the 95 percent VOC emission control of storage vessels only apply to storage vessels that have a PTE greater than or equal to 6 tpy of VOC emissions. The VOC cost of control per ton of VOC reduced would be less if a combustion device or VRU is used to control VOC emissions from multiple storage vessels because the cost for the additional storage vessels would only include storage vessel retrofit costs, and the overall VOC emission reductions would increase.

We recommend an alternative RACT level of control for storage vessels that have a PTE VOC at or greater than 6 tpy that have actual emissions less than that on a continuing basis. For these storage vessels, if it can be demonstrated that the storage vessel has actual emissions less than 4 tpy for 12 consecutive months, we recommend that they be allowed to maintain and show continued compliance that their emissions are below 4 tpy in lieu of requiring 95 percent control. This alternative recommendation acknowledges that there are storage vessels that have a PTE greater than or equal to 6 tpy whose actual emissions have declined over time, usually because of declining production. This alternative RACT recommendation is informed by the 2012 NSPS, where we concluded that, based on “the cost-effectiveness, the secondary environmental impacts

³⁵ 77 FR 49490, August 16, 2012.

and the energy impacts...BSER for reducing VOC emissions from storage vessel affected facilities is not represented by continued control when their sustained (i.e., for 12 consecutive months) uncontrolled emission rates fall below 4 tpy.”³⁶

In summary, we recommend the following as RACT for storage vessels in the oil and natural gas industry:

- (1) RACT for Condensate Storage Vessels: Reduce emissions by 95 percent continuously from condensate storage vessels with a PTE $\geq$ 6 tpy of VOC; or demonstrate (based on 12 consecutive months of uncontrolled actual emissions) and maintain uncontrolled actual VOC emissions from storage vessels with a PTE greater than or equal to 6 tpy at less than 4 tpy.³⁷
- (2) RACT for Crude Oil Storage Vessels: Reduce emissions by 95 percent continuously from crude oil storage vessels with a PTE $\geq$ 6 tpy of VOC; or demonstrate (based on 12 consecutive months of uncontrolled actual emissions) and maintain uncontrolled actual VOC emissions from storage vessels with a PTE greater than or equal to 6 tpy at less than 4 tpy.³⁸

4.5 Factors to Consider in Developing Storage Vessel Compliance Procedures

4.5.1 Compliance Recommendations When Using a Control Device

Improper design or operation of the storage vessel and its control system can result in occurrences where peak flow overwhelms the storage vessel and its capture systems, resulting in emissions that do not reach the control device, effectively reducing the control efficiency. We believe that it is essential that operators employ properly designed, sized, and operated storage vessels to achieve effective emission control. We believe that such efforts on the part of owners and operators can result in more effective control of VOC emissions from storage vessels.

In order to ensure that VOC emissions are reduced by at least 95 percent (the recommended RACT level of control) from a storage vessel when using a control device or other

³⁶ Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards Final Amendments. Federal Register Notice. (78 FR 58429, September 23, 2013).

³⁷ We recommend that, prior to allowing the use of the uncontrolled 4 tpy actual VOC emissions rate for compliance purposes, air agencies require sources demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy for 12 consecutive months. After such demonstration, we recommend that air agencies require that sources demonstrate continued compliance with the uncontrolled actual VOC emission rate each month.

³⁸ See footnote 37.

control measure (such as routing to a process), the storage vessel should be equipped with a cover that is connected through a closed vent system that captures and routes emissions to the control device (or process). We recommend cover, closed vent system and control device design and compliance measures to ensure that control measures meet the RACT level of control. Recommended cover and closed vent system design and operation measures are specified in sections 4.5.1.1 and 4.5.1.2. Recommended control device operation and monitoring provisions for specified controls to ensure compliance are presented in sections 4.5.1.3 and 4.5.1.4. The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part.

4.5.1.1 *Recommendations for Cover Design*

The cover and all openings on the cover (e.g., access hatches, sampling ports, pressure relief valves, and gauge wells) should form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel. Each cover opening should be secured in a closed, sealed position (gasket lid or cap) whenever material is in the unit except when it is necessary to open as follows:

- (1) To add material to or remove material from the unit (including openings necessary to equalize or balance the internal pressure of the unit following changes in the level of material in the unit);
- (2) To inspect or sample the material in the unit;
- (3) To inspect, maintain, repair, or replace equipment located in the unit; or
- (4) To vent liquids, gases or fumes from the unit through a closed vent system designed and operated in accordance with specified closed vent system requirements (see section 4.5.1.2) or to a process.

It is recommended that air agencies require the storage vessel thief hatch be equipped, maintained and operated with a weight, or other mechanism, to ensure that the lid remains properly seated. It is recommended that air agencies require the gasket material for the hatch be selected based on composition of the fluid in the storage vessel and weather conditions.

It is also recommended that air agencies require monthly olfactory, visual and auditory inspections of covers for defects that could result in air emissions. Any detected defects should be required to be repaired as soon as practicable.

4.5.1.2 *Recommendations for Closed Vent Systems*

The closed vent system should be designed and operated with no detectable emissions (which can be monitored by monthly olfactory, visual and auditory inspections). It is recommended that air agencies require that any detected defects be repaired as soon as practicable.

With the exception of low leg drains, high point bleeds, analyzer vent, open-ended valves and safety devices, if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process, it is recommended that air agencies require owners and operators either:

(1) Install, calibrate, maintain and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere; or

(2) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

4.5.1.3 *Recommendations When “Routing to a Process” or to a VRU*

Routing to a process would entail routing emissions via a closed vent system to any enclosed portion of a process unit where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product and/or recovered. Vapor recovery units and flow lines that “route emissions to a process” would be considered part of the process and would not be considered control devices that are subject to standards, but the recommended cover and closed vent system design, operation and monitoring requirements specified in sections 4.5.1.1 and 4.5.1.2 would apply.

4.5.1.4 *Recommendations for Control Device Operation and Monitoring*

If a control device is used to comply with the recommended 95 percent VOC emission reduction RACT level of control, it is recommended that air agencies require that the device

operate at all times when gases, vapors, and fumes are vented from the storage vessel subject to VOC emission requirements through the closed vent system to the control device.

For control devices used to meet the recommended RACT, it is recommended that air agencies require owners and operators follow the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

If an owner or operator complies with the recommended RACT by using a combustion device, it is recommended that air agencies require initial and periodic performance testing (no later than 60 months after the initial performance test) to demonstrate initial and continued compliance with the recommended RACT level of control. Additionally, for each combustion device used to comply with the recommended continuous 95 percent VOC emission reduction, it is recommended that air agencies require owners and operators conduct the following control device compliance assurance measures: (1) Monthly visual inspections or monitoring to confirm that the pilot is lit when vapors are routed to it. (2) Monthly inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22 of appendix A of part 60. It is recommended that the observation period be 15 minutes and that devices be operated with no visible emissions, except for periods not to exceed a total of one minute during any 15-minute period. (3) Monthly olfactory, visual and auditory inspections associated with the combustion device to ensure system integrity.

4.5.2 Compliance Recommendations When Complying with the 4 tpy VOC Emissions Alternative Limitation

If the alternative RACT recommendation to determine and maintain the uncontrolled actual VOC emissions from a storage vessel that has a PTE to emit greater than or equal to 6 tpy at less than 4 tpy without considering control is used, it is recommended that air agencies first require that a source demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, it is recommended that air agencies require that the source determine the uncontrolled actual VOC emission rate each month using a generally accepted model or calculation methodology. It is also recommended that such calculations be based on the average throughput for the month. If the monthly emissions determination indicates that VOC emissions from a storage vessel subject to VOC emission control requirements increases to 4 tpy or greater and the increase is not

associated with fracturing or refracturing of a well feeding the storage vessel, it is recommended that air agencies require that the source comply with the 95 percent VOC emission reduction RACT level of control recommendation or that emissions be routed to a VRU.

5.0 COMPRESSORS

Compressors are mechanical devices that increase the pressure of natural gas and allow the natural gas to be transported from the production site, through the supply chain, and to the consumer. The types of compressors that are used by the oil and natural gas industry as prime movers are reciprocating and centrifugal compressors. This chapter discusses the sources of VOC emissions from these compressors. This chapter also provides control techniques used to reduce VOC emissions from these compressors, along with costs and emission reductions. Finally, this chapter provides a discussion of our recommended RACT and the associated VOC emission reductions and costs for both reciprocating and centrifugal compressors.

5.1 Applicability

For the purposes of this CTG, the emissions and emission reductions discussed herein would apply to centrifugal and reciprocating compressors in the oil and natural gas industry located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. As noted in section 3.2 of this document, we did not evaluate RACT for compressors located at a well site, or an adjacent well site and servicing more than one well site.

5.2 Process Description and Emission Sources

5.2.1 Process Description

5.2.1.1 *Reciprocating Compressors*

In a reciprocating compressor, natural gas enters the suction manifold, and then flows into a compression cylinder where it is compressed by a piston driven in a reciprocating motion by the crankshaft powered by an internal combustion engine. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The compressor rod packing system consists of a series of flexible rings that create a seal around the piston rod to prevent gas from escaping between the rod and the inboard cylinder head. However, over time, during operation of the compressor, the rings become worn and the packaging system needs to be

replaced to prevent excessive leaking from the compression cylinder. See Figure 5-1 for a depiction of a typical rod compressor packing system configuration.³⁹

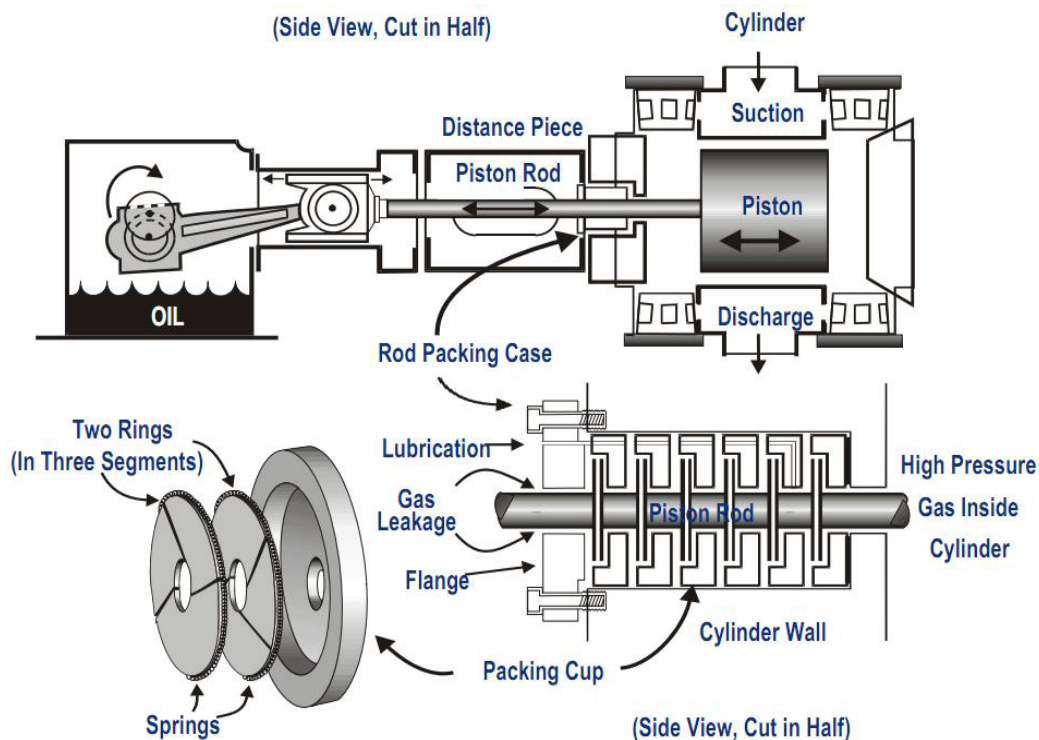


Figure 5-1. Typical Reciprocating Compressor Rod Packing System Diagram

5.2.1.2 Centrifugal Compressors

Centrifugal compressors use a rotating disk or impeller to increase the velocity of the natural gas where it is directed to a divergent duct section that converts the velocity energy to pressure energy. These compressors are primarily used for continuous, stationary transport of natural gas in the processing and transmission systems. Many centrifugal compressors use wet (meaning oil) seals around the rotating shaft to prevent natural gas from escaping where the compressor shaft exits the compressor casing. The wet seals use oil which is circulated at high pressure to form a barrier against compressed natural gas leakage. The circulated oil entrains and

³⁹ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR Program. 2006.

adsorbs some compressed natural gas that may be released to the atmosphere during the seal oil recirculation process. Figure 5-2 illustrates the wet seal compressor configuration.⁴⁰

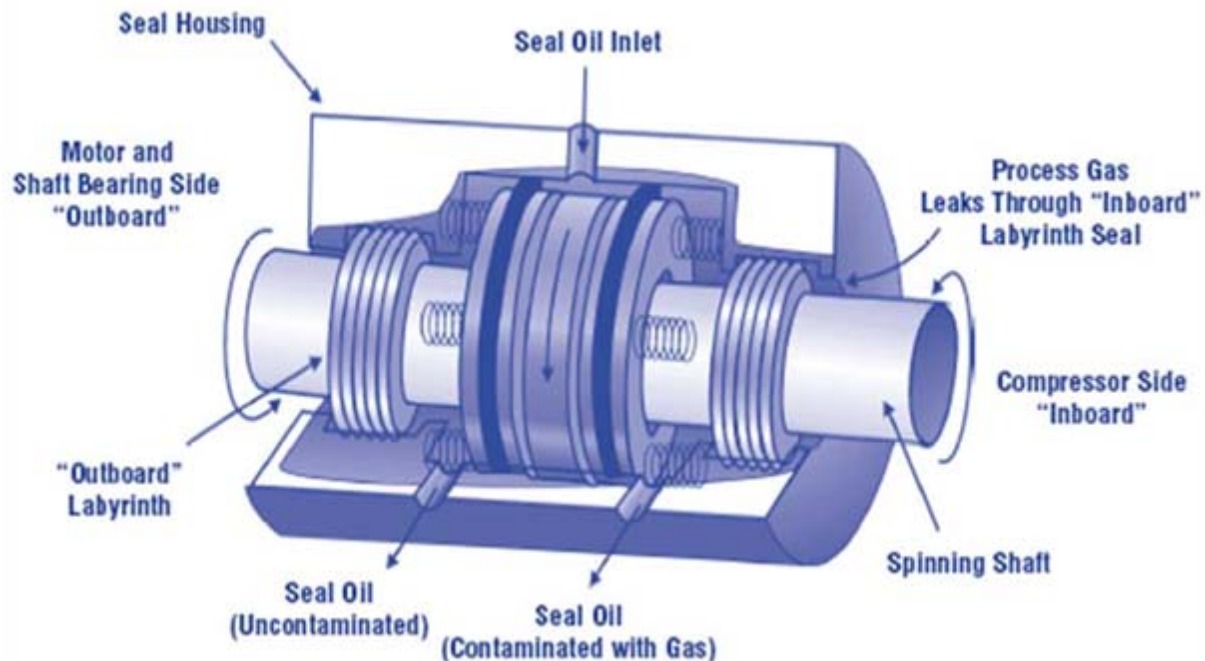


Figure 5-2. Typical Centrifugal Compressor Wet Seal

Alternatively, dry seals can be used in place of wet seals in centrifugal compressors. Dry seals prevent leakage by using the opposing force created by hydrodynamic grooves and springs (see Figure 5-3). The hydrodynamic grooves are etched into the surface of the rotating ring affixed to the compressor shaft. When the compressor is not rotating, the stationary ring in the seal housing is pressed against the rotating ring by springs. When the compressor shaft rotates at high speed, compressed natural gas has only one pathway to leak down the shaft, and that is between the rotating and stationary rings. This natural gas is pumped between the grooves in the rotating and stationary rings. The opposing force of high-pressure natural gas pumped between the rings and springs trying to push the rings together creates a very thin gap between the rings through which little natural gas can leak. While the compressor is operating, the rings are not in

⁴⁰ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. Natural Gas STAR Program. October 2006.

contact with each other and, therefore, do not wear or need lubrication. O-rings seal the stationary rings in the seal case.⁴¹

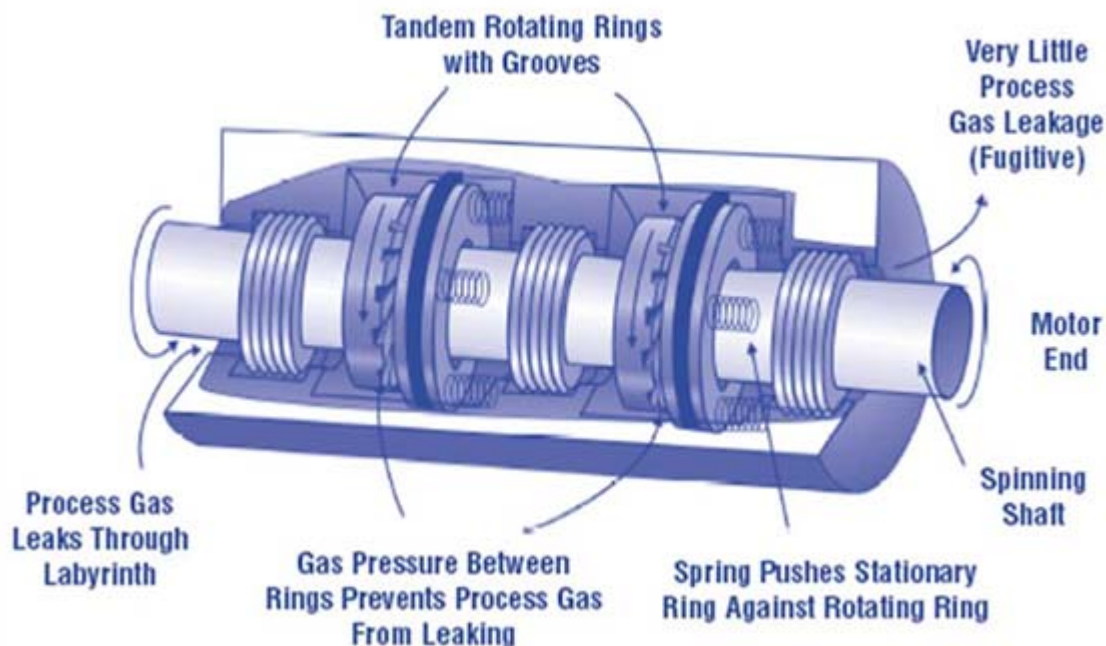


Figure 5-3. Typical Centrifugal Compressor Tandem Dry Seal

Natural gas emissions from wet seal centrifugal compressors have been found to be higher than dry seal compressors primarily due to the off-gassing of the entrained natural gas from the oil. This natural gas is not suitable for sale and is either released to the atmosphere, flared, or routed back to a process. In addition to lower natural gas leakage (and therefore lower emissions), dry seals have been found to have lower operation and maintenance costs than wet seal compressors because they are a mechanically simpler design, require less power to operate, and are more reliable. For the same reasons we explained in the 2012 NSPS and the 2015 NSPS proposal, we are not recommending RACT for dry seal compressors and instead include the use of a dry seal in place of a wet seal system as an available control option for reducing VOC emissions from wet seal centrifugal compressors (discussed in section 5.3.1.2 of this chapter). During the rulemakings for the 2012 NSPS and 2016 NSPS, we found that the dry seal system and the option of routing to a process both had at least a 95 percent control efficiency.

⁴¹ Ibid.

5.2.2 Emissions Data

5.2.2.1 Summary of Major Studies and Emissions

Several studies have been conducted that provide leak estimates from reciprocating and centrifugal compressors. Table 5-1 lists these studies, along with the type of information contained in the study. In addition to these sources, we evaluated the peer reviewer and public comments received on the EPA’s white paper, “Oil and Natural Gas Sector Compressors.”⁴²

Table 5-1. Major Studies Reviewed for Emissions Data⁴³

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options ^j
Inventory of Greenhouse Gas Emissions and Sinks ^a	EPA	Annual	Nationwide	X	
Greenhouse Gas Reporting Program (Annual Reporting; Current Data Available for 2011-2013) ^b	EPA	2014	Facility-Level	X	X
Methane Emissions from the Natural Gas Industry ^c	EPA/Gas Research Institute (GRI)	1996	Nationwide	X	
Natural Gas STAR Program ^{d,e}	EPA	1993-2010	Nationwide	X	X
Natural Gas Industry Methane Emission Factor Improvement Study ^f	URS Corporation, UT Austin, and EPA	2011	None	Emission Factors Only	
Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production: Summary and Analysis of API and ANGA Survey Responses ^g	API/ANGA	2012	Regional	X ^h	
Economic Analysis of Methane Emissions Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries ⁱ	ICF International (Prepared for the Environmental Defense Fund (EDF))	2014	Regional	X	X

⁴² U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Compressors. Report for Oil and Natural Gas Sector Compressors Review Panel*. Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at <http://www.epa.gov/airquality/oilandgas/2014papers/20140415compressors.pdf>.

⁴³ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

^a U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. <https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html>.

^b U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2014.

^c U.S. Environmental Protection Agency/GRI. National Risk Management Research Laboratory. Research and Development. *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*. Prepared for the U.S. Department of Energy, Energy Information Administration. EPA-600/R-96-080h. June 1996.

^d U.S. Environmental Protection Agency. *Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR. Environmental Protection Agency. 2006.

^e U.S. Environmental Protection Agency. *Lessons Learned: Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. Natural Gas STAR. Environmental Protection Agency. October 2006.

^f URS Corporation/University of Texas at Austin. 2011. *Natural Gas Industry Methane Emission Factor Improvement Study, Final Report*. December 2011.

http://www.utexas.edu/research/ceer/GHG/files/FReports/XA_83376101_Final_Report.pdf.

^g American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA). *Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production. Summary and Analysis of API and ANGA Survey Responses*. Final Report. September 21, 2012.

^h The API/ANGA study provided information on equipment counts that could augment nationwide emissions calculations. No source emission information was included.

ⁱ ICF International. *Economic Analysis of Methane Emissions Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries*. Prepared for the Environmental Defense Fund. March 2014.

^j An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

5.2.2.2 Representative Reciprocating and Centrifugal Compressor Emissions

The centrifugal compressor methane emission factors used for processing are based on emission factor data for wet seals and dry seals from a sampling of wet seal and dry seal centrifugal compressor data that was used to calculate emissions in the GHG Inventory.

For gathering and boosting station reciprocating compressors, the 2011 NSPS TSD emission factors were used because they are considered to be the best representative emission factors at this time. Emission factors in the Clearstone study,⁴⁴ which are expressed in thousand standard cubic feet per cylinder, were multiplied by the average number of cylinders per gathering and boosting station reciprocating compressor. The volumetric methane emission rate was converted to a mass emission rate using a density of 41.63 pounds of methane per thousand cubic feet. This conversion factor was developed assuming that methane is an ideal gas and using the ideal gas law to calculate the density. A summary of the reciprocating compressor methane

⁴⁴ Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*. 2006.

emission factors used for this analysis is presented in Table 5-2. Once the mass methane emission rate was calculated, ratios were used to estimate VOC emissions using the methane to VOC pollutant ratios developed in the 2011 Gas Composition Memorandum. The specific ratio that was used to convert methane emissions to VOC emissions is 0.278 pounds VOC per pound of methane for the production and processing segments. Table 5-3 presents a summary of the estimated methane and VOC emissions per reciprocating and centrifugal compressor (in tpy) for the production and processing segments.

Table 5-2. Methane Emission Factors for Reciprocating and Centrifugal Compressors⁴⁵

Oil and Gas Industry Segment	Reciprocating Compressors			Centrifugal Compressors	
	Methane Emission Factor (scfh-cylinder)	Average Number of Cylinders	Pressurized Factor (Percent of Hours/Year Compressor Pressurized)	Wet Seal Methane Emission Factor (scfm)	Dry Seal Methane Emission Factor (scfm)
Gathering & Boosting Stations	25.9 ^a	3.3	79.1%	N/A ^c	N/A ^c
Processing	57 ^b	2.5	89.7%	47.7 ^d	6 ^d

^a Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*. 2006.

^b U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry: Volume 8 – Equipment Leaks*. Table 4-14.

^c U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry: Volume 11 – Compressor Driver Exhaust*. 1996 Report does not report any centrifugal compressors in the production or gathering/boosting segments, therefore no emission factor data were published for those two segments.

^d U.S. Environmental Protection Agency. *Methodology for Estimating CH₄ and CO₂ Emissions from Petroleum Systems. Greenhouse Gas Inventory: Emission and Sinks 1990-2012*. Washington, DC. April 2014.

⁴⁵ U.S. Environmental Protection Agency/GRI. Research and Development, National Risk Management Research Laboratory. *Methane Emissions from the Natural Gas Industry*. Prepared for the U.S. Department of Energy, Energy Information Administration. EPA-600/R-96-080h. June 1996.

Table 5-3. Baseline VOC Emission Estimates for Reciprocating and Centrifugal Compressors^a

Industry Segment/Compressor Type	Baseline Emission Estimates (tpy)	
	Methane	VOC
Reciprocating Compressors		
Gathering and Boosting Stations	12.3	3.42
Processing	22	6.12
Centrifugal Compressors (Wet seals)		
Processing	210.53	19.1
Centrifugal Compressors (Dry seals)		
Processing	26	2.4

^a For centrifugal compressors, it was assumed that 75 percent of the natural gas that is compressed is pipeline quality gas and 25 percent of the natural gas is production quality.

5.3 Available Controls and Regulatory Approaches

5.3.1 Available VOC Emission Control Options

Available controls for reducing VOC emissions from reciprocating and centrifugal compressors are presented in sections 5.3.1.1 and 5.3.1.2 of this chapter.

5.3.1.1 *Reciprocating Compressors*

Potential control options for reducing emissions from reciprocating compressors include control techniques that limit the leaking of natural gas past the piston rod packing. These options include: (1) increasing or specifying the frequency of the replacement of the compressor rod packing, (2) increasing or specifying the frequency of the replacement of the piston rod, (3) specifying the refitting or realignment of the piston rod, and (4) routing of emission to a process through a closed vent system under negative pressure. In addition to these options, there are emerging control techniques where specific analyses have not yet been conducted. For example, there may be potential for reducing VOC emission by updating rod packing components made from newer materials which can help improve the life and performance of the rod packing system (economic rod packing replacement) and capturing gas from the reciprocating compressor and routing it back to the compressor engine to be used as fuel. These emerging VOC emissions control techniques are discussed briefly below, along with our

evaluation of the frequency of compressor rod packing/piston rod replacement and piston rod refitting and realignment control options.

We do not believe that combustion is a technically feasible control option because, as detailed in the 2011 NSPS TSD, routing of emissions to a control device can cause positive back pressure on the packing, which can cause safety issues due to gas backing up in the distance piece area and engine crankcase in some designs. While considering the option of routing of emissions to a process through a closed vent system under negative pressure, we determined that the negative pressure requirement not only ensures that all the emissions are conveyed to the process, it also avoids the issue of inducing back pressure on the rod packing and the resultant safety concerns. Although this option can be used in some circumstances, it cannot be applied in every installation. As a result, these options (i.e., routing of emissions to a control device, routing of emissions to a process through a closed vent system under negative pressure) were not further considered under this CTG.

Frequency of Rod Packing Replacement

For reciprocating compressors, one of the options for reducing VOC emissions is a maintenance task that would increase or specify the frequency of replacement of the rod packing in order to reduce the leakage of natural gas past the piston rod. Over time, the packing rings wear and allow more natural gas to escape around the piston rod. Regular replacement of these rings reduces VOC emissions. Therefore, this control technique is considered to be an available VOC emission control technique for reciprocating compressors.

Description

As noted previously, reciprocating compressor rod packing consists of a series of flexible rings that fit around a shaft to create a seal against leakage. As the rings wear, they allow more compressed natural gas to escape, increasing rod packing emissions. Rod packing emissions typically occur around the rings from slight movement of the rings in the cups as the rod moves, but can also occur through the “nose gasket” around the packing case, between the packing cups, and between the rings and shaft. If the fit between the rod packing rings and rod is too loose, more compressed natural gas will escape. Periodically replacing the packing rings ensures the correct fit is maintained between packing rings and the rod.⁴⁶

⁴⁶ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR Program. 2006.

Control Effectiveness

As discussed above, regular replacement of the reciprocating compressor rod packing can reduce the leaking of natural gas across the piston rod. The potential emission reductions for gathering and boosting stations and the processing segment were calculated by comparing the average rod packing emissions with the average emissions from newly installed and worn-in rod packing.

Based on industry information from the Natural Gas STAR Program, we have determined that the additional cost of shortening the replacement period more frequently than every three years or every 26,000 hours would not be justified based on the additional emission reductions that would be achieved.⁴⁷ Therefore, we analyzed emission reductions that would result from replacing worn packing with newly installed packing at a frequency of every three years or every 26,000 hours. For the baseline, we assumed that rod packing is replaced every four years. The analysis uses Equation 1 for estimating gathering and boosting station emission reductions, and Equation 2 for estimating processing segment emission reductions that would result from replacing worn packing with newly installed packing at a frequency of every 3 years or every 26,000 hours.⁴⁸

$$\text{Equation 1} \quad R_{WP}^{G\&B} = \frac{Comp_{Existing}^{G\&B} (E_{G\&B} - E_{New}) \times C \times O \times 8760}{10^6}$$

Where:

$R_{WP}^{G\&B}$ = Potential methane emission reductions from gathering and boosting stations by replacing worn packing with newly installed packing, in million cubic feet per year (MMcf/year);

$Comp_{Existing}^{G\&B}$ = Number of existing gathering and boosting station compressors;

$E_{G\&B}$ = Methane emission factor for gathering and boosting stations, in cubic feet per hour per cylinder (25.9 scfh-cylinder);

⁴⁷ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews*. 40 CFR Parts 60 and 63. Response to Public Comments on Proposed Rule. August 23, 2011 (76 FR 52738). pg. 102.

⁴⁸ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution – Background Technical Support Document for Proposed Standards*. July 2011. EPA Document Number EPA-453/R-11-002.

E_{New} = Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder⁴⁹ for this analysis;

C = Average number of cylinders for gathering and boosting stations (i.e., 3.3);

O = Percent of time during the calendar year the average gathering and boosting station is in the operating and standby pressurized modes, 79.1 percent;

8760 = Number of hours in a year;

10^6 = Number of cubic feet in a million cubic feet.

$$\text{Equation 2} \quad R_p = \frac{Comp_{Existing}^P (E_P - E_{New}) \times C \times O \times 8760}{10^6}$$

Where:

R_p = Potential methane emission reductions from processing compressors replacing worn packing to newly installed packing, in million cubic feet per year (MMcf/year);

$Comp_{Existing}^P$ = Number of existing processing compressors;

E_P = Methane emission factor for processing compressors, in cubic feet per hour per cylinder, 57 scfh-cylinder;

E_{New} = Average emissions from a newly installed rod packing, assumed to be 11.5 cubic feet per hour per cylinder⁵⁰ for this analysis;

C = Average number of cylinders for processing compressors (i.e., 2.5);

O = Percent of time during the calendar year the average processing compressor is in the operating and standby pressurized modes, 89.7 percent;

8760 = Number of hours in a year;

10^6 = Number of cubic feet in a million cubic feet.

Table 5-4 presents a summary of the potential emission reductions for reciprocating compressor rod packing replacement for gathering and boosting stations and processing segment compressors based on the percent natural gas reduction calculated from the above equations. The emissions of VOC were estimated using the methane emissions calculated

⁴⁹ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR Program. 2006.

⁵⁰ Ibid.

above and the methane-to-VOC ratio developed for each of the segments in the 2011 Gas Composition Memorandum.

Table 5-4. Estimated Annual Reciprocating Compressor Emission Reductions from Increasing the Frequency of Rod Packing Replacement

Oil and Natural Gas Segment	Individual Compressor Emission Reductions (tons/compressor-year)	
	Methane	VOC
Gathering and Boosting	6.84	1.9
Processing	17.58	4.89

Cost Impacts

Costs for the specified frequency of replacement of reciprocating compressor rod packing documented in the 2011 NSPS TSD were obtained from a Natural Gas STAR Lessons Learned document which estimated the cost to replace the packing rings to be \$1,712 per cylinder (converted from 2008 dollars to 2012 dollars). It was assumed that rod packing replacement would occur during planned shutdowns and maintenance and, therefore, no additional travel costs would be incurred for implementing the rod packing replacement program. In addition, no costs were included for monitoring because the rod packing replacement is based on the number of hours that the compressor operates or the period of time since the previous replacement. The 2011 NSPS TSD analysis assumed that, at baseline, the replacement of rod packing for reciprocating compressors occurs on average every four years based on industry information from the Natural Gas STAR Program. The cost impacts are based on the replacement frequency of the rod packing every 26,000 hours that the reciprocating compressor operates in the pressurized mode.

The 26,000 hour replacement frequency used for the cost impacts in the 2011 NSPS TSD was determined using a weighted average of the annual percentage that the reciprocating compressors are pressurized. The weighted average percentage was calculated to be 98.9 percent. This percentage was multiplied by the total number of hours in 3 years to obtain a value of 26,000 hours. Assuming an interest rate of 7 percent, the capital recovery factors (based on replacing the rod packing every 3 years or 26,000 hours) were calculated to be 0.3122 and 0.3490 for gathering and boosting stations and the processing segment, respectively. The capital

costs were calculated using the average rod packing cost of \$1,712 (converted from \$1,620 in 2008 dollars to 2012 dollars) and the average number of cylinders per compressor (assumed to be 3.3 cylinders for gathering and boosting stations and 2.5 cylinders for processing segment compressors).⁵¹ The annual costs were calculated using the capital costs and the capital recovery factors. Table 5-5 presents a summary of the capital and annual costs for gathering and boosting stations and the processing segment.

There are monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement. Monetary savings associated with the amount of gas saved with reciprocating compressor rod packing replacement was estimated using a natural gas price of \$4.00 per Mcf.⁵² Table 5-5 presents the annual costs with savings and cost of control for reciprocating rod packing replacement for gathering and boosting stations and the processing segment.

Reciprocating compressor rod packing replacement prevents the escape of natural gas from the piston rod. In addition to reducing VOC emissions, there would be a co-benefit of reducing other emissions (such as methane) as a result of increasing the frequency of rod packing replacement.

Table 5-5. Cost of Control for Increasing the Frequency of Reciprocating Compressor Rod Packing Replacement

Oil and Gas Segment	Capital Cost (\$2012) ^a	Annual Costs per Compressor (\$/compressor-year)		VOC Cost of Control (\$/ton)	
		Without Savings	With Savings	Without Savings	With Savings
Gathering and Boosting	\$5,650	\$2,153	\$566	\$1,131	\$298
Processing	\$4,280	\$1,631	(\$2,443)	\$334	(\$500)

^a 2011 TSD 2008 dollars converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflator (5.69 percent).

⁵¹ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution – Background Technical Support Document for Proposed Standards*. July 2011. EPA Document Number EPA-453/R-11-002.

⁵² U.S. Energy Information Administration. *Annual U.S. Natural Gas Wellhead Price*. U.S. Energy Information Administration Natural Gas Navigator. Retrieved online on December 12, 2010 at <http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm>.

Frequency of Replacement and/or Realignment/Retrofitting of the Piston Rod

Like the packing rings, piston rods on reciprocating compressors also deteriorate. Piston rods, however, wear more slowly than packing rings, having a life of about 10 years.⁵³ Rods wear “out-of-round” or taper when poorly aligned, which affects the fit of packing rings against the shaft (and therefore the tightness of the seal) and the rate of ring wear. An out-of-round shaft not only seals poorly, allowing more leakage, but also causes uneven wear on the seals, thereby shortening the life of the piston rod and the packing seal. Replacing or upgrading the rod can reduce reciprocating compressor rod packing emissions. Also, upgrading piston rods by coating them with tungsten carbide or chrome reduces wear over the life of the rod. We assume that operators will choose, at their discretion, when to replace/realign or retrofit the rod as part of regular maintenance procedures and replace the rod when appropriate when the compressor is out of service for other maintenance such as rod packing replacement. Therefore, we did not consider this option any further.

Updated Rod Packing Material

Although specific analyses have not been conducted, there may be potential for reducing VOC emissions by updating rod packing components made from newer materials, which can help improve the life and performance of the rod packing system. One option is to replace the bronze metallic rod packing rings with longer lasting carbon-impregnated Teflon rings. Compressor rods can also be coated with chrome or tungsten carbide to reduce wear and extend the life of the piston rod.⁵⁴ Although changing the rod packing material has been identified as a potential VOC emission reduction option for reciprocating compressors, there is insufficient information on its emission reduction potential and use throughout the industry.

Economic Rod Packing Replacement

Another option facilities can use that has the potential to reduce costs and emissions is for facilities to use specific financial objectives and monitoring data to determine emission levels at which it is cost-effective to replace rings and rods. Benefits of calculating and utilizing this “economic replacement threshold” include VOC emission reductions and natural gas cost savings. Using this approach, one Natural Gas STAR partner reportedly achieved savings of over

⁵³ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Reducing Methane Emissions from Compressor Rod Packing Systems*. Natural Gas STAR Program. 2006.

⁵⁴ Ibid.

\$233,000 annually at 2006 gas prices. An economic replacement threshold approach would also result in operational benefits, including a longer life for existing equipment, improvements in operating efficiencies, and long-term savings.⁵⁵

Gas Recovery (Routing of Emissions to a Process)

Description

Another control option for reciprocating compressors includes control techniques that recover natural gas leaking past the piston rod packing. We are aware of a system that captures the natural gas that would otherwise be vented and routes it back to the compressor engine to be used as fuel.⁵⁶ The vent gases are passed through a valve train that includes a demister and then are injected into the engine intake air after the air filter. In general, the technology consists of recovering vented emissions from the rod packing under negative pressure and routing these emissions of otherwise vented gas to the air intake of a reciprocating internal combustion engine that would burn the gas as fuel to augment the normal fuel supply. The system's computerized air/fuel control system would then adjust the normal fuel supply to accommodate the increased fuel made available from the recovered emissions and thereby take advantage of the recovered emissions while avoiding an overly rich fuel mixture.

Subpart OOOO, as well as subpart OOOOa, provide a compliance option for reciprocating compressors that allows collecting emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure and routing the rod packing emissions to a process through a closed vent system. Both of the above systems, if installed using a cover and closed vent system meeting the subpart OOOO and subpart OOOOa requirements, could potentially be used for this compliance option.

Control Effectiveness

One estimate obtained by the EPA states that the gas recovery system can result in the elimination of over 99 percent of VOC emissions that would otherwise occur from the venting of the emissions from the compressor rod packing.⁵⁷ The emissions that would have been vented are combusted in the compressor engine to generate power.

⁵⁵ Ibid.

⁵⁶ REM Technology Inc. and Targa Resources. *Reducing Methane and VOC Emissions*. Presentation for the 2012 Natural Gas STAR Annual Implementation Workshop.

⁵⁷ REM Technology Inc., et al. *Profitable Use of Vented Emission in Oil & Gas Production*. Prepared with support from the Climate Change and Emissions Management Corporation (CCEMC). 2013.

If the facility is able to route rod packing vents to a VRU system, it is possible to recover approximately 95-100 percent of emissions. If the gas is routed to a flare, approximately 95 percent of the VOC emissions could be reduced.

Cost Impacts

One estimate reported that the cost per engine would be approximately \$12,000 (does not include installation costs). Some costs would be mitigated by fuel gas savings, as using the captured gas to displace some of the purchased fuel would require less fuel to be purchased in order to run the compressor engine. The fuel cost saving based on a 4-throw compressor with moderate leak rate would be an estimated \$6,500 per year.⁵⁸ This technique is discussed further in the Natural Gas STAR PRO Fact Sheet titled “Install Automated Air/Fuel Ratio Controls”.⁵⁹ This document reported an average fuel gas savings of 78 Mcf/day per engine with the gas recovery system installed. Based on our review of information on this technology, we conclude that this technology has merit and would provide better emission reductions than increasing the replacement of rod packing from every 4 years to every 3 years since the emissions would be captured under negative pressure, allowing all emissions to be routed to the engine. It is our understanding that this technology may not be applicable to every compressor installation and situation.

For a VRU, assuming the proper equipment is already available at the facility, capturing the rod packing emissions would require minimal costs. The investment would only need to include the cost of piping and installation. While we have not obtained a cost estimate specifically for routing rod packing vents to a VRU, this process has been studied for dehydrators and would be similar for rod packing systems. According to the Natural Gas STAR PRO Fact Sheet titled “Pipe Glycol Dehydrator to Vapor Recovery Unit,”⁶⁰ the cost for planning and installing additional piping is approximately \$2,000. Routing to a VRU also provides additional incentive as there is a value associated with recovered gas. However, the installation of a VRU to only capture rod packing emissions may not be economically viable if an additional compressor system is required. If the VRU is already present at the facility, the incremental cost

⁵⁸ REM Technology Inc. Presentation to the U.S. Environmental Protection Agency on December 1, 2011. EPA Docket ID No. EPA-HQ-OAR-2010-0505.

⁵⁹ U.S. Environmental Protection Agency. Gas STAR PRO No. 104. *Install Automated Air/Fuel Ratio Controls*. 2011.

⁶⁰ U.S. Environmental Protection Agency. Gas STAR PRO No. 203. *Pipe Glycol Dehydrator to Vapor Recovery Unit*. 2011.

to capture the rod packing vent gas can be recovered from the value of the additional captured natural gas.

Although gas recovery has been identified as a potential VOC emission reduction option for reciprocating compressors, there is insufficient information on its availability as a reasonably available control option for reducing reciprocating compressor VOC emissions. However, we recommend that air agencies consider this technology as a compliance option when considering the RACT recommendations presented in section 5.4 of this chapter.

5.3.1.2 Centrifugal Compressors Equipped with Wet Seals

Potential control options to reduce emissions from centrifugal compressors equipped with wet seals include control techniques that limit the leaking of natural gas across the rotating shaft, and capture and destruction of the emissions by routing emissions to a process (e.g., a compressor or fuel gas system) or to a combustion device (discussed in detail in sections 4.3.1.2 of chapter 4). We evaluate below three available control options: (1) converting wet seals to dry seals, (2) routing emissions to a fuel gas system or compressor (process), and (3) routing emissions to a combustion device.

Converting Wet Seals to Dry Seals

Description

We evaluated the use of centrifugal compressor dry seals as an available VOC control option for wet seal centrifugal compressors. As noted in section 5.2 of this chapter, the VOC emission profile from the use of dry seals is considerably less than from the use of wet seals. Replacing wet seals with dry seals can, therefore, substantially reduce VOC emissions across the rotating shaft compared to wet seals, while simultaneously reducing operating costs and enhancing compressor efficiency compared to wet seals. During normal operation, dry seals leak at a rate of 6 scfm methane per compressor.⁶¹ While this is equivalent to a wet seal's leakage rate at the seal face, wet seals generate additional emissions during degassing of the circulating oil. Gas separated from the seal oil before the oil is recirculated is usually vented to the atmosphere,

⁶¹ U.S. Environmental Protection Agency. Lessons Learned Document. *Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. October 2006.

bringing the total leakage rate for tandem wet seals to 47.7 scfm methane per compressor.^{62,63} It is not practical or feasible in all situations, however, to retrofit an existing wet seal compressor with a dry seal compressor. We have received information that indicates that the conversion process requires a significant period of time to complete and the compressor would need to be out of commission for the conversion period.

Control Effectiveness

The emission reductions that would occur by replacing wet seal compressors with a dry seal compressor were calculated by subtracting the dry seal emissions from the emissions from a centrifugal compressor equipped with wet seals. We used the centrifugal compressor emission factors in Table 5-2 and estimated that VOC emissions would be reduced by 16.7 tpy per compressor.

Cost Impacts

The Natural Gas STAR Program estimated the cost of retrofitting dry seals on a centrifugal compressor equipped with wet seals to be \$324,000 (\$342,439 in 2012 dollars) for a two-seal dry seal system, which includes the cost of both seals and the dry gas conditioning, monitoring, control console and installation.⁶⁴ The annual costs were calculated as the capital recovery of the capital cost assuming a 20-year equipment life and 7 percent interest, which is approximately \$32,324 per compressor. The Natural Gas STAR Program estimated that the annual operation and maintenance savings from the installation of a dry seal compressor is \$88,300 (\$93,325 in 2012 dollars) in comparison to a wet seal compressor. In addition, the installation of dry seals reduces natural gas emissions by 10,721 Mscf/yr⁶⁵ which results in an estimated natural gas savings of \$42,883 per year assuming a natural gas price of \$4/Mcf. A summary of the capital and annual costs for replacing a wet seal compressor with a dry seal compressor is presented in Table 5-6 along with the VOC cost of control. As noted above, we

⁶² U.S. Environmental Protection Agency, et al. *Methane's Role in Promoting Sustainable Development in the Oil and Natural Gas Industry*. World Gas Conference 10/2009.

⁶³ U.S. Environmental Protection Agency. *Methodology for Estimating CH₄ and CO₂ Emissions from Natural Gas Systems. Inventory of U.S. Greenhouse Gas Emission and Sinks: 1990-2012*. Washington, DC. Annex 3. Table A-129.

⁶⁴ U.S. Environmental Protection Agency. Lessons Learned Document. *Replacing Wet Seals with Dry Seals in Centrifugal Compressors*. October 2006.

⁶⁵ The natural gas savings was calculated by using the 16.7 tpy VOC reduction and dividing by the VOC/methane weight ratio of 0.278 to determine the amount of methane reduction that would be reduced (60.1 tpy). The methane emission reductions were converted to volumetric natural gas reductions assuming a natural gas density of 0.02082 tons/Mcf and an 82.9 volume percent conversion factor of methane to natural gas.

have received information that indicates that the conversion process requires a significant period of time to complete and the compressor would need to be out of commission during the conversion period. Because of this, a facility may have to provide a temporary compressor in the interim that would add additional costs to the cost estimates we present in Table 5-6.

Table 5-6. Cost of Control of Replacing a Wet Seal Compressor with a Dry Seal Compressor

Oil & Natural Gas Segment	Capital Cost (\$2012)	Annual Costs Per Compressor (\$/compressor-year)		VOC Cost of Control (\$/ton)	
		Without Savings ^a	With O&M and Natural Gas Savings ^b	Without Savings	With O&M and Natural Gas Savings
Processing	\$342,439	\$32,324	(\$103,884)	\$1,931	(\$6,205)

^a Includes only the annualized capital cost of the retrofit of the dry seal system (20 years, 7 percent interest).

^b Includes the annualized capital cost, annual operation and maintenance (O&M) savings and annual natural gas savings.

Routing Emissions to a Compressor or Fuel Gas System (Process)

Description

One option for reducing VOC emissions from the compressor wet seal fluid degassing system is to route the captured emissions back to the compressor suction or fuel system or other beneficial use (referred to collectively as routing to a process). Routing to a process would entail routing emissions via a closed vent system to any enclosed portion of a process unit (e.g., compressor or fuel gas system) where the emissions are predominantly recycled, consumed in the same manner as a material that fulfills the same function in the process, transformed by chemical reaction into materials that are not regulated materials, incorporated into a product, or recovered. Emissions that are routed to a process can result in the same or greater emission reductions as would have been achieved had the emissions been routed through a closed vent system to a combustion device. Table 5-7 presents a summary of the estimated emission reductions from routing emissions from the wet seal fluid degassing system to a process. For purposes of this analysis, we assume that routing VOC emissions from a wet seal fluid degassing

system to a process reduces VOC emissions greater than or equal to a combustion device (i.e., greater than or equal to 95 percent).

Table 5-7. Estimated Annual Centrifugal Compressor VOC Emission Reductions for Routing Wet Seal Fluid Degassing System to a Process^{66,67}

Oil & Gas Segment	Individual Compressor VOC Emission Reductions (tons/compressor-year)
Processing	≥ 18.1

Cost Impacts

The capital cost of a system to route the seal oil degassing system to a process is estimated to be \$23,252,⁶⁸ converting to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflator (Change in GDP: Implicit Price Deflator from 2008 to 2012 (5.69 percent)).⁶⁹ The estimated costs include an intermediate pressure degassing drum, new piping, gas demister/filter, and a pressure regulator for the fuel line. The annual costs were estimated to be \$2,553 assuming a 15-year equipment life at 7 percent interest.

Potential natural gas savings for this option were estimated to be 12 Mcf/yr and assumes that greater than or equal to 95 percent of the 47.7 scfm methane emissions are controlled, an annual operating factor of 43.6 percent, and the 82.9 volume percent conversion factor of methane to natural gas. Assuming a natural gas savings of \$4/Mcf, the natural gas savings equates to approximately \$47,553 per year. Table 5-8 presents a summary of the cost of control for routing emissions to a process.

⁶⁶ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

⁶⁷ Ibid.

⁶⁸ Ibid.

⁶⁹ U.S. Bureau of Economic Analysis. *Gross Domestic Product: Implicit Price Deflator (GDPDEF)*, retrieved from FRED, Federal Reserve Bank of St. Louis. <https://research.stlouisfed.org/fred2/series/GDPDEF/> March, 26, 2015.

Table 5-8. VOC Cost of Control for Routing Wet Seal Fluid Degassing System to a Process^a

Oil and Gas Segment	Capital Cost (\$2012) ^a	Annual Costs per Compressor (\$/compressor-year)		VOC Cost of Control (\$/ton)	
		Without Savings	With Savings	Without Savings	With Savings
Processing	\$23,252	\$2,553	(\$47,553)	\$141	(\$2,621)

^a 2011 TSD 2008 dollars converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflator (Change in GDP: Implicit Price Deflator from 2008 to 2012 (5.69 percent)).⁷⁰

Routing Emissions to a Combustion Device

Description

Combustion devices are commonly used in the oil and natural gas industry to combust VOC emission streams. Typical combustion devices used in the oil and natural gas industry to control VOC emissions and their control efficiency are discussed in greater detail in section 4.3.1.2 of chapter 4 of this document. Similar to the analysis of storage vessels, for this analysis, we assumed that the entrained natural gas from the seal oil that is removed in the degassing process would be directed to a combustion device that achieves a 95 percent reduction of VOC. The wet seal emissions in Table 5-2 were used along with the control efficiency to calculate the emission reductions. Table 5-9 presents a summary of the estimated emission reductions from routing emissions from the wet seal to a combustion device.

Table 5-9. Estimated Annual VOC Emission Reductions for Routing Wet Seal Fluid Degassing System to a Combustion Device⁷¹

Oil & Gas Segment	Individual Compressor VOC Emission Reductions (tons/compressor-year)
Processing	18.1

⁷⁰ Ibid.

⁷¹ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

Cost Impacts

Routing the captured gas from the centrifugal compressor wet seal degassing system to an existing combustion device or installing a new combustion device has associated capital and operating costs. The capital and annual costs of the combustion device (an enclosed flare for the analysis) were calculated using the methodology in the EPA Control Cost Manual.⁷² The heat content of the gas stream was calculated using information from the 2011 Gas Composition Memorandum. Table 5-10 presents a summary of the capital and annual costs for wet seals routed to a flare, as well as the VOC cost of control. There is no cost savings estimated for this option because the recovered natural gas is combusted.

Table 5-10. Cost of Control for Routing Wet Seal Fluid Degassing System to a Combustion Device

Industry Segment	Capital Cost (\$)		Annual Cost per Compressor (\$/compressor-year)		VOC Cost of Control New CD (\$/ton)	VOC Cost of Control Existing CD (\$/ton)
	New CD	Existing CD	New CD	Existing CD		
Processing	\$71,783	\$23,252	\$114,146	\$3,311	\$6,292	\$183

CD = Control Device

5.3.2 Existing Federal, State and Local Regulations

5.3.2.1 Federal Regulations that Specifically Require Control of VOC Emissions

Under the 2012 NSPS and 2016 NSPS, reciprocating compressors are required to limit VOC emissions by replacing the rod packing on or before 26,000 hours of operation or 36 months since the previous rod packing replacement. Alternatively, an owner or operator is allowed to route rod packing emissions to a process through a closed vent system under negative pressure. For centrifugal compressors in the processing segment, the 2012 NSPS and 2016 NSPS require that VOC emissions be reduced from each centrifugal compressor wet seal fluid degassing system by 95 percent.

⁷² U.S. Environmental Protection Agency. *OAQPS Control Cost Manual: Sixth Edition* (EPA 452/B-02-001). Research Triangle Park, NC.

5.3.2.2 *State and Local Regulations that Specifically Require Control of VOC Emissions*

States may have permitting restrictions on VOC emissions that may apply to an emissions source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met and, often, how the source must be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

Montana requires oil and natural gas well facilities to control emissions from the time the well is completed until the source is registered or permitted. Each piece of oil or natural gas well facility equipment, with VOC vapors of 200 Btu/scf or more with a PTE greater than 15 tpy, is required to (1) capture and route emissions to a natural gas pipeline, (2) route to a smokeless combustion device equipped with an electronic ignition device or a continuous burning pilot system meeting the requirements of 40 CFR 60.18 and operating at 95 percent or greater control efficiency, or (3) route to air pollution control equipment with equal or greater control efficiency than a smokeless combustion device. This includes the control of emissions from compressor engines used for transmission of natural gas (Registration of Air Contaminant Sources, Rule 17.8.1711 Oil or Gas Well Facilities Emission Control Requirements).

Colorado (Regulation 7, XVII.B.3.b and c) requires that uncontrolled actual hydrocarbon emissions from wet seal fluid degassing systems on wet seal centrifugal compressors be controlled by at least 95 percent, unless the centrifugal compressor is subject to 40 CFR part 60, subpart OOOO. Additionally, Regulation 7 requires that rod packing on any reciprocating compressor located at a natural gas compressor station be replaced every 26,000 hours of operation or every 36 months, unless the reciprocating compressor is subject to 40 CFR part 60, subpart OOOO.

5.4 Recommended RACT Level of Control

For reciprocating compressors, there are federal and state regulations that require the periodic replacement of reciprocating compressor packing. The federal regulations (the 2012 NSPS and 2016 NSPS) require the replacement of reciprocating compressor rod packing every 3 years or on or before 26,000 hours of operation. The state regulation (Colorado) requires the

replacement of reciprocating compressor rod packing every 26,000 hours of operation or every 36 months. The 2012 NSPS and 2016 NSPS also provide the alternative of routing rod packing emissions to a process via a closed vent system under negative pressure.

As noted in section 5.3 of this chapter, the most significant volume of VOC emissions are associated with piston rod packing systems. We found that, under the best conditions, regular rod packing replacement, when carried out approximately every three years, effectively controls emissions and helps prevent excessive rod wear. The cost of control for requiring the replacement of reciprocating packing at this frequency was estimated to be \$1,132 per ton of VOC reduced without savings and \$298 per ton of VOC reduced considering savings for gathering and boosting station compressors, and about \$334 per ton of VOC reduced without savings, and an overall net savings per ton of VOC reduced for processing segment reciprocating compressors considering savings. Based on the emission reductions, costs (considering gas savings) and existing and currently implemented regulations that require the replacement of the reciprocating compressor packing every 36 months or on or before 26,000 hours of operation, we recommend this control option as RACT for reciprocating compressors in the production and processing segments (excluding compressors at the well site). We also recommend that air agencies provide operators the compliance alternative of routing rod packing emissions to a process via a closed vent system under negative pressure.

For centrifugal compressors, there are already federal, state and local regulations that require the capture and 95 percent control of emissions from wet seal fluid degassing systems from centrifugal compressors. Although dry seal systems have low VOC emissions and the option of routing to a process has at least a 95 percent control efficiency, the replacement of wet seals with dry seals and routing to a process may not be technically feasible or practical options for some centrifugal compressors. The integration of a centrifugal compressor into an operation may require a certain compressor size or design that is not available in a dry seal model, and, in the case of capture of emissions with routing to a process, there may not be downstream equipment capable of handling a low-pressure fuel source. As a result of our evaluation of the technical feasibility and practicality of existing available controls, we recommend RACT be 95 percent control of emissions from the wet seal degassing system, which can be achieved by using a closed vent system and routing emissions to a combustor or routing the emissions back to the compressor or fuel line (routing to the process). For the processing segment, we assume that

there is an existing combustion device onsite and the estimated cost of control would be about \$183 per ton of VOC reduced for facilities to route emissions to the existing combustion device, or about \$141 per ton of VOC reduced for facilities to route the captured emissions back to the compressor or fuel line.

In summary, we recommend the following as RACT for compressors:

- (1) RACT for Reciprocating Compressors Located Between the Wellhead and Point of Custody Transfer to the Natural Gas Transmission and Storage Segment (Excludes the Well Site): We recommend that each reciprocating compressor reduce VOC emissions by replacing the rod packing on or before 26,000 hours of operation or 36 months since the last rod packing replacement. We also recommend that an alternative be provided to allow routing of rod packing emissions to a process via a closed vent system under negative pressure in lieu of the specified rod packing replacement periods. We do not recommend that RACT apply to individual reciprocating compressors located at a well site, or an adjacent well site and servicing more than one well site.
- (2) RACT for Centrifugal Compressors Using Wet Seals Located Between the Wellhead and Point of Custody Transfer to the Natural Gas Transmission and Storage Segment (Excludes the Well Site): We recommend that each centrifugal compressor using wet seals reduce VOC emissions from each wet seal fluid gassing system by reducing VOC emissions by 95 percent. We do not recommend that RACT apply to individual centrifugal compressors using wet seals located at a well site, or an adjacent well site and servicing more than one well site.

5.5 Factors to Consider in Developing Compressor Compliance Procedures

5.5.1 Reciprocating Compressor Compliance Recommendations

In order to ensure and demonstrate compliance with the recommended RACT for reciprocating compressors, we recommend that air agencies require facilities to maintain a record of the date of the most recent reciprocating compressor rod packing replacement, monitor and keep records of the number of hours of operation and/or track the number of months since the last rod packing replacement for each reciprocating compressor (to meet the requirement that the packing is changed out on or before the total number of hours of operation reaches 26,000 hours

or the number of months since the most recent rod packing replacement reaches 36 months) and maintain records of instances where the reciprocating compressor was not operated in compliance with RACT. This may require the installation of an operating hours meter on the engine to track the number of hours of operation. We also recommend that air agencies require annual reports of the cumulative hours of operation or number of months since packing replacement for each reciprocating compressor and instances when there were deviations where the reciprocating compressor was not operated in compliance with the recommended RACT.

For applications in which operators choose to opt for the alternative of routing of rod packing emissions to a process via a closed vent system under negative pressure, it is recommended that air agencies require facilities to maintain records of the date of installation of a rod packing emissions collection system and closed vent system and maintain records of instances of deviations in cases where the reciprocating compressor was not operated in compliance with requirements. We also recommend that air agencies require annual reports for each reciprocating compressor complying with this option indicating when there were deviations where the reciprocating compressor was not operated in compliance with the recommended RACT. Recommended cover and closed vent system design and operation measures are specified in sections 5.5.3 and 5.5.4.

The appendix to this document presents example model rule language that incorporates compliance elements recommended in this section that air agencies may choose to use in whole or in part.

5.5.2 Centrifugal Compressor Equipped with a Wet Seal Recommendations

In order to ensure that VOC emissions are reduced by at least 95 percent (the recommended RACT level of control) from a centrifugal compressor equipped with a wet seal when using a control device or other control measure (such as routing to a process), the centrifugal compressor should be equipped with a cover that is connected through a closed vent system that routes emissions to the control device (or process) that meets the RACT level of control. Recommended cover and closed vent system design and operation measures are specified in sections 5.5.3 and 5.5.4. Recommended control device operation and monitoring provisions for specified controls to ensure compliance are presented in section 5.5.5.

The appendix of this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part.

5.5.3 Recommendations for Cover Design

The cover and all openings on the cover should form a continuous impermeable barrier over the entire surface area of the liquid in the wet seal fluid degassing system (for centrifugal compressors), and of the rod packing emissions collection system (for reciprocating compressors). Each cover opening should be secured in a closed, sealed position (e.g., covered by a gasketed lid or cap) except during those times when it is necessary to use an opening as follows:

- (1) To inspect, maintain, repair, or replace equipment; or
- (2) To vent gases or fumes from the unit, through a closed vent system designed and operated in accordance with closed vent system requirements (see section 5.5.4), to a control device or to a process.

It is recommended that air agencies require olfactory, visual and auditory inspections of covers for defects that could result in air emissions on a monthly basis. We recommend air agencies require that any detected defects be repaired as soon as practicable.

5.5.4 Recommendations for Closed Vent Systems

The closed vent system should be designed and operated with no detectable emissions (using a 500 ppm detection level, as measured using Method 21 of appendix A-7 of Part 60, and ongoing monthly olfactory, visual and auditory inspections). It is recommended that air agencies require that any detected defects be repaired as soon as practicable.

With the exception of low leg drains, high point bleeds, analyzer vent, open-ended valves and safety devices, if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process, air agencies should require that owners or operators either:

- (1) Install, calibrate, maintain and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings and either sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open

such that the stream is being, or could be, diverted away from the control device or process to the atmosphere; or

- (2) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

5.5.5 Recommendations for Control Device Operation and Monitoring

If a control device is used to comply with the recommended 95 percent VOC emission reduction RACT level of control, we advise that the device be required to operate at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system through the closed vent system to the control device. The following paragraphs present select emission control options and suggested operation and monitoring requirements, as appropriate to ensure compliance with the recommended RACT level of control.

Enclosed Combustion Devices

If an enclosed combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) is used to meet the 95 percent VOC emission reduction RACT level of control, it should be designed to reduce the mass content of VOC emissions by 95 percent or greater and be: (1) maintained in a leak free condition, (2) installed and operated with a continuous burning pilot flame, and (3) operated with no visible emissions.

It is recommended that the visible emissions test (using section 11 of EPA Method 22, 40 CFR part 60, appendix A-7) be performed at least once every calendar month. If a combustion device fails the visible emissions test, sources should be required to follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. It is recommended that all inspection, repair and maintenance activities for each unit be recorded in a maintenance and repair log that can be made available for inspection. Following return to operation from maintenance or repair activity, each device should be required to pass a Method 22, 40 CFR part 60, appendix A-7 visual emissions test.

It is recommended that air agencies require that sources meeting the 95 percent VOC emission reduction RACT level of control by routing emissions to a combustion device conduct performance tests and/or design analyses that demonstrate that the combustion device being used meets the required 95 percent VOC emission reduction RACT level of control (see section F of

the appendix to this document for performance testing procedures for control devices that we recommend be used to demonstrate performance requirements).

Routing to a Process

Routing to a process would entail routing emissions via a closed vent system to any enclosed portion of a process unit where the emissions are predominantly recycled, consumed in the same manner as a material that fulfills the same function in the process, transformed by chemical reaction into materials that are not regulated materials, incorporated into a product, or recovered. Vapor recovery units and flow lines that “route emissions to a process” would be considered part of the process and would not be considered control devices that are subject to standards, but the recommended cover and closed vent system design, operation and monitoring requirements specified in sections 5.5.3 and 5.5.4 would apply.

6.0 PNEUMATIC CONTROLLERS

The oil and natural gas industry uses a variety of process control devices to operate valves that regulate pressure, flow, temperature and liquid levels. Most instrumentation and control equipment falls into one of three categories: (1) pneumatic, (2) electrical, or (3) mechanical. Of these, only pneumatic devices are direct sources of air emissions. Pneumatic controllers are pneumatic devices used throughout the oil and natural gas industry as part of the instrumentation to control the position of valves and may be actuated using pressurized natural gas (natural gas-driven) or may be actuated by another means such as a pressurized gas other than natural gas, solar, or electric. This chapter describes pneumatic controllers that are used in the oil and natural gas industry, including their function and associated emissions. This chapter also presents control techniques used to reduce VOC emissions from these pneumatic controllers, along with costs and emission reductions. Finally, this chapter discusses our recommended RACT and the associated VOC emission reductions and costs for pneumatic controllers.

6.1 Applicability

For the purposes of this CTG, a pneumatic controller is an automated instrument used to maintain a process condition such as liquid level, pressure, pressure differential and temperature. The emissions and emission controls discussed herein would apply to natural gas-driven pneumatic controllers in the oil and natural gas industry located from the wellhead to a natural gas processing plant (including the natural gas processing plant) or from the wellhead to the point of custody transfer to an oil pipeline.

6.2 Process Description and Emission Sources

6.2.1 Process Description⁷³

Natural gas-driven pneumatic controllers come in a variety of designs for a variety of uses. For the purposes of this CTG, they are characterized primarily by their emission characteristics:

- (1) *Continuous bleed pneumatic controllers* are used to modulate flow, liquid level, or pressure, and gas is vented continuously at a rate that may vary over time. Continuous bleed controllers are further subdivided into two types based on their bleed rate:
 - a. *Low-bleed*, having a bleed rate of less than or equal to 6 standard cubic feet per hour (scfh).
 - b. *High-bleed*, having a bleed rate of greater than 6 scfh.
- (2) *Intermittent bleed or snap-acting pneumatic controllers* release gas only when they open or close a valve or as they throttle the gas flow.
- (3) *Zero-bleed pneumatic controllers* do not bleed natural gas to the atmosphere. These natural gas-driven pneumatic controllers are self-contained devices that release gas to a downstream pipeline instead of to the atmosphere.

Pneumatic controllers often make use of available high-pressure natural gas to operate or control a valve. The supply gas pressure is modulated by a process condition, and then flows to the valve controller where the signal is compared with the process set point to adjust gas pressure in the valve actuator. In these natural gas-driven pneumatic controllers, natural gas may be released intermittently with every actuation of the valve. In other designs, natural gas may be released continuously from the valve control pilot. The rate at which the continuous release occurs is referred to as the bleed rate. Bleed rates are dependent on the design and operating characteristics of the device. Similar designs will have similar steady state rates when operated under similar conditions. It is our understanding that self-contained devices that release natural gas to a downstream pipeline instead of to the atmosphere have no emissions. “Closed loop” systems are applicable only in instances with very low pressure⁷⁴ and may not be suitable to

⁷³ U.S. Environmental Protection Agency. *Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

⁷⁴ Memorandum to Bruce Moore, U.S. Environmental Protection Agency, from Denise Grubert, EC/R Incorporated. *Meeting Minutes from EPA Meeting with the American Petroleum Institute (API)*. October 2010.

replace many applications of continuous or intermittent bleed pneumatic devices. Therefore, this CTG does not address these self-contained devices further.

Intermittent controllers are devices that only emit gas during actuation and do not have a continuous bleed rate. The actual amount of emissions from an intermittent controller is dependent on the amount of natural gas vented per actuation and how often it is actuated. Bleed devices also vent an additional volume of gas during actuation, in addition to the controller's bleed stream. Since actuation emissions serve the controller's functional purpose and can be highly variable, the emissions characterized for high-bleed and low-bleed devices in this analysis (as described in section 6.2.2) account for only the continuous flow of emissions (i.e., the bleed rate) and do not include emissions directly resulting from actuation. Intermittent controllers are assumed to have zero bleed emissions. For most applications (but not all), intermittent controllers serve functionally different purposes than bleed devices. Therefore, because the total emissions are dependent on the application in which they are used, we do not consider their use to be a technically practical control option for all continuous bleed controllers.

As previously indicated, not all pneumatic controllers are natural gas driven. At sites with a continuous and reliable source of electricity, controllers can be actuated by an instrument air system that uses compressed air instead of natural gas. These sites may also use mechanical or electrically powered pneumatic controllers. In some instances, solar-powered controllers may be feasible. Because these devices are not natural gas driven, they do not directly release natural gas or VOC. However, electrically powered systems have energy impacts, with associated secondary impacts related to generation of the electrical power required to drive the instrument air compressor system. To our knowledge, natural gas processing plants are the only facilities in the oil and natural gas industry that are likely to have electrical service sufficient to power an instrument air system, and most existing natural gas processing plants use instrument air instead of natural gas-driven devices.⁷⁵

⁷⁵ U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices*. EPA-600/R/-96-080k. June 1996.

6.2.2 Emissions Data

6.2.2.1 Summary of Major Studies and Emissions

In the evaluation of the emissions from pneumatic controllers and the potential options available to reduce VOC emissions, numerous studies were consulted. Table 6-1 lists these references with an indication of the type of relevant information contained in each reference. In addition to these sources, we evaluated the peer reviewer and public comments received on the EPA’s white paper, “Oil and Natural Gas Sector Pneumatic Devices.”⁷⁶

Table 6-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options ¹
Greenhouse Gas Reporting Program (Annual Reporting; Current Data Available for 2011-2013) ^a	EPA	2014	Facility-Level	X	X
Inventory of Greenhouse Gas Emissions and Sinks ^b	EPA	Annual	Nationwide/ Regional	X	
Methane Emissions from the Natural Gas Industry ^c	EPA/GRI	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry ^d	EPA/GRI	1996	Nationwide	X	
Methane Emissions from the U.S. Oil Industry ^e	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States ^f	WRAP	2005	Regional	X	
Natural Gas STAR Program ^g	EPA	2000 – 2010	Voluntary	X	X
Measurements of Methane Emissions from Natural Gas Production Sites in the United States ^h	Multiple Affiliations, Academic and Private	2013	Nationwide	X	

⁷⁶ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Pneumatic Devices. Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel*. Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at <http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf>.

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options ^l
Determining Bleed Rates for Pneumatic Devices in British Columbia ⁱ	The Prasino Group	2013	British Columbia	X	
Air Pollutant Emissions from the Development, Production, and Processing of Marcellus Shale Natural Gas ^j	Carnegie Mellon University	2014	Regional (Marcellus Shale)	X	
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries ^k	ICF International	2014	Nationwide	X	X

^a U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC.

^b U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. <https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html>.

^c U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report*. EPA-600/R-96-080b. June 1996; U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology*. EPA-600/R-96-080c. June 1996; U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors*. EPA-600/R-96-080e. June 1996; and U.S. Environmental Protection Agency. *Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices*. EPA-600/R-96-080k. June 1996.

^d U.S. Environmental Protection Agency/GRI. *Methane Emissions from the U.S. Petroleum Industry. Draft Report*. June 14, 1996.

^e ICF Consulting. *Estimates of Methane Emissions from the U.S. Oil Industry*. Prepared for the U.S. Environmental Protection Agency. 1999.

^f ENVIRON International Corporation. *Oil and Gas Emission Inventories for the Western States*. Prepared for Western Governors Association. December 27, 2005.

^g U.S. Environmental Protection Agency. *Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR. Washington, DC. October 2006.

^h Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. *Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking*. July 2011.

ⁱ U.S. Environmental Protection Agency. *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas Star. Washington, DC. 2006.

^j U.S. Environmental Protection Agency. Pro Fact Sheet No. 301. *Convert Pneumatics to Mechanical Controls*. Office of Air and Radiation: Natural Gas Star. Washington, DC. September 2004.

^k Canadian Environmental Technology Advancement Corporation (CETAC)-WEST. *Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Pneumatic Instruments*. Prepared for the Canadian Association of Petroleum Producers. May 2008.

¹ An “X” in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

6.2.2.2 Representative Pneumatic Controller Device Emissions

For purposes of this CTG, continuous bleed pneumatic controllers are classified into two types based on their emissions rates: (1) high-bleed controllers, and (2) low-bleed controllers. A controller is considered to be high-bleed when the continuous bleed emissions are in excess of 6 scfh, while low-bleed devices bleed at a rate less than or equal to 6 scfh.⁷⁷

In support of the development of the 2012 NSPS and 2016 NSPS, and this CTG, we consulted information in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic devices, subpart W of the GHGRP, the GHG Inventory, as well as pneumatic controller vendor information used during the development of the 2012 NSPS.⁷⁸ The data obtained from vendors included emission rates, costs, and any other pertinent information for each pneumatic controller model (or model family). All pneumatic controllers that a vendor offered were itemized and inquiries were made into the specifications of each device and whether it was applicable to oil and natural gas operations. High-bleed and low-bleed devices were differentiated using the 6 scfh threshold.

Although, by definition, a low-bleed device can emit up to 6 scfh, through vendor research, a typical low-bleed device available currently on the market emits lower than the maximum rate allocated for the device type. Specifically, low-bleed devices on the market today have bleed rates from 0.2 scfh up to 5 scfh. Similarly, the available bleed rates for a high-bleed device vary significantly from venting as low as 7 scfh to as high as 100 scfh.^{79,80} While the vendor data provided useful information on specific makes and models, it did not yield sufficient information about the prevalence of each model type in the population of devices in the oil and

⁷⁷ The classification of high-bleed and low-bleed devices originated from a report by Pacific Gas & Electric (PG&E) and the Gas Research Institute (GRI) in 1990 titled “Unaccounted for Gas Project Summary Volume.” This classification was adopted for the October 1993 Report to Congress titled “Opportunities to Reduce Anthropogenic Methane Emissions in the United States”. As described on page 2-16 of the report, “devices with emissions or ‘bleed rates’ of 0.1 to 0.5 cubic feet per minute are considered to be ‘high-bleed’ types (PG&E 1990).” This range of bleed rates is equivalent to 6 to 30 cubic feet per hour.

⁷⁸ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution – Background Technical Support Document for Proposed Standards*. July 2011. EPA Document Number EPA-453/R-11-002.

⁷⁹ U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2010.

⁸⁰ All rates are listed at an assumed supply gas pressure of 20 psig.

natural industry, which is an important factor in developing a representative emission factor. Therefore, in support of this CTG, we have determined that the best available emission estimates for pneumatic controllers in the production segment are from the GHGRP. For the natural gas processing segment, we determined that the quantified representative methane emissions from a continuous bleed pneumatic controller based on natural gas emission rates presented in Volume 12 of the EPA/GRI report used in the 2012 NSPS TSD is the best available emissions information.⁸¹

The basic approach used for this analysis of emissions from pneumatic controllers was to first approximate the natural gas emissions from an average high-bleed and low-bleed pneumatic controller in the production and processing segments and then estimate methane and VOC emissions using a representative gas composition from the 2011 Gas Composition Memorandum. A bleed rate of 1.39 scfh was used for a low-bleed controller, and a bleed rate of 37.3 scfh was used for a high-bleed controller. The specific gas composition ratio used for the production and processing segments was 0.278 pounds VOC per pound methane. Table 6-2 summarizes the estimated bleed emissions for a representative pneumatic controller by industry segment (for production and processing segments) and device type.

Table 6-2. Average Emission Rates for High-Bleed and Low-Bleed Pneumatic Controllers in the Oil and Natural Gas Industry^a

Industry Segment	High-Bleed (tpy)		Low-Bleed (tpy)	
	Methane	VOC	Methane	VOC
Oil and Natural Gas Production ^{b,c}	5.3	1.47	0.2	0.06
Natural Gas Processing ^d	1.00	0.28	1.0	0.28

^a The conversion factor used in this analysis is 1 Mcf of methane is equal to 0.0208 tons methane.

^b Natural gas production methane emissions are derived from the GHGRP (subpart W).

^c Oil production methane emissions are derived from the GHGRP (subpart W). It is assumed only continuous bleed devices are used in oil production.

^d Natural gas processing segment methane emissions are derived from Volume 12 of the 1996 EPA/GRI report. Emissions from devices in the processing segment were determined based on data available for snap-acting and continuous bleed devices. Further distinction between high-

⁸¹ GRI/EPA Research and Development. Methane Emissions from the Natural Gas Industry; Volume 12: Pneumatic Devices. (1996) EPA-600/R-96-0801. Table 4-11, page 56.

and low-bleed could not be determined based on available data. For the natural gas processing segment, it is assumed that existing natural gas plants have already replaced pneumatic controllers with other types of controls (i.e., an instrument air system) and any high-bleed devices that remain are safety related.

For the natural gas processing segment, this analysis assumes that existing natural gas plants have already replaced pneumatic controllers with other types of controls (i.e., an instrument air system) and any high-bleed devices that remain are safety related.

6.3 Available Controls and Regulatory Approaches

6.3.1 Available VOC Emission Control Options

Although pneumatic controllers have relatively small emissions individually, due to the large population of these devices, the cumulative VOC emissions for the industry are significant. We are not aware of any add-on controls that are or can be used to reduce VOC emissions from gas-driven pneumatic controllers. The following sections provide a summary of options for reducing VOC emissions from pneumatic controllers including: (1) replacing high-bleed controllers with low-bleed controllers or zero-bleed controllers; (2) driving controllers with instrument air rather than natural gas, using non-gas-driven controllers; and (3) enhanced maintenance.

Sections 6.3.1.1 and 6.3.1.2 discuss the control of VOC emissions by replacing a high-bleed device with a low-bleed device, and driving controllers with instrument air rather than natural gas, including the estimated costs of these options. Given applicability, efficiency and the expected costs, other options (i.e., mechanical controls and enhanced maintenance) are only briefly discussed in sections 6.3.1.3 and 6.3.1.4.

6.3.1.1 *Install a Low-Bleed Device in Place of a High-Bleed Device*

Description

As discussed previously, low-bleed controllers generally provide the same operational function as a high-bleed controller, but have lower continuous bleed emissions.

Control Effectiveness

We estimate on average that 1.41 tons of VOC will be reduced annually per device in the production segment from installing a low-bleed device in place of a high-bleed device. There are certain situations in which replacing and retrofitting devices are not feasible, such as instances where a minimal response time is needed, cases where large valves require a high-bleed rate to

actuate, or a safety isolation valve is involved. Based on criteria provided by the Natural Gas STAR Program, we assumed about 80 percent of high-bleed devices can be replaced with low-bleed devices throughout the production segment.

Applicability of low-bleed controllers may depend on the function carried out by the controller. Low-bleed pneumatic controllers may not be applicable for replacement of high-bleed devices because a process condition may require a fast or precise control response to minimize deviation from the desired set point. A slower acting low-bleed controller could potentially result in damage to equipment and/or become a safety issue because it may not be able to respond as quickly as a high-bleed controller. An example of this is a compressor where pneumatic controllers may monitor the suction and discharge pressure and actuate a recycle when one or the other is out of the specified target range. Other scenarios for fast and precise control include transient (non-steady state) situations where a gas flow rate may fluctuate widely or unpredictably. This situation requires a responsive high-bleed device to ensure that the gas flow can be controlled in all situations. Temperature and level controllers are typically present in control situations that are not prone to fluctuate as widely or where the fluctuation can be readily and safely accommodated by the equipment. Therefore, such processes can typically accommodate control from a low-bleed device, which is slower acting and less precise.

Cost Impacts

Costs were based on vendor research as a result of updating and expanding upon the information given in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic controllers.⁸² As Table 6-3 indicates, the average cost for a low-bleed pneumatic controller is \$2,698, while the average cost for a high-bleed pneumatic controller is \$2,471.⁸³ In order to analyze cost impacts, the average cost to install a new low-bleed pneumatic controller was annualized for a 15-year period using a 7 percent interest rate. This equates to an annualized cost of around \$271 per low-bleed device for the production segment.

⁸² U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

⁸³ Costs are estimated in 2012 U.S. dollars.

Table 6-3. Cost Projections for Representative Pneumatic Controllers^a

Device	Minimum Cost (\$2012)	Maximum Cost (\$2012)	Average Cost (\$2012)
High-Bleed Controller	\$387	\$7,398	\$2,471
Low-Bleed Controller	\$554	\$9,356	\$2,698

^a 2011 NSPS TSD 2008 dollars converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflator (5.69 percent). During the development of the 2012 NSPS, major pneumatic controller vendors were surveyed for costs, emission rates and any other pertinent information.

Monetary savings associated with retaining natural gas that would have been emitted was estimated based on a natural gas value of \$4.00 per Mcf.⁸⁴ The use of a low-bleed pneumatic controller is estimated to reduce methane emissions by 5.1 tpy (245 Mcf/yr) (using the conversion factor of 0.0208 tons methane per 1 Mcf) over the use of a high-bleed pneumatic controller. Assuming natural gas in the production segment is 82.8 percent methane by volume, this equals 296 Mcf natural gas recovered per year. Therefore, the value of recovered natural gas from one pneumatic controller in the production segment is approximately \$1,184. Table 6-4 presents the estimated cost of control per ton of VOC reduced for replacing a high-bleed pneumatic controller with a new low-bleed pneumatic controller in the production segment of the oil and natural gas industry.

Table 6-4. VOC Cost of Control for Replacing an Existing High-Bleed Pneumatic Controller with a New Low-Bleed Pneumatic Controller

Segment	Average Capital Cost per Unit (\$2012) ^{a,c}	Total Annual Costs per Unit (\$2012/yr) ^{b,c}		VOC Cost of Control (\$2012/ton) ^c	
		Without Savings	With Savings	Without Savings	With Savings
Oil and Natural Gas Production	\$2,698	\$296	(\$886)	\$209	(\$625)

^a Average capital cost of a low-bleed device as summarized in Table 6-3.

^b Annualized cost assume a 7 percent interest rate over a 15-year equipment lifetime.

^c Cost data from the 2011 TSD converted to 2012 dollars using the Federal Reserve Economic Data GDP Price Deflator (5.69 percent).

⁸⁴ U.S. Energy Information Administration. *Annual U.S. Natural Gas Wellhead Price*. U.S. Energy Information Administration. *Natural Gas Navigator*. Retrieved online on 12 Dec 2010 at <http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm>.

6.3.1.2 *Instrument Air Systems*

Description

The major components of an instrument air conversion project include the compressor, power source, dehydrator and volume tank. The following is a description of each component as described in the Natural Gas STAR document, “Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air”:⁸⁵

- (1) Compressors used for instrument air delivery are available in various types and sizes, from centrifugal (rotary screw) compressors to reciprocating piston (positive displacement) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank. For reliability, a full spare compressor is normally installed. A minimum amount of electrical service is required to power the compressors.
- (2) A critical component of the instrument air control system is the power source required to operate the compressor. Since high-pressure natural gas is abundant and readily available, natural gas pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and in remote locations, however, a reliable source of electric power can be difficult to ensure. In some instances, solar-powered, battery-operated air compressors can be cost-effective for remote locations, and reduce both VOC emissions and energy consumption. Small natural gas-driven fuel cells are also being developed.
- (3) Dehydrators, or air dryers, are also an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.

⁸⁵ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. 2006.

- (4) The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high-pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools without affecting the process control functions.

Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic controller. The use of instrument air eliminates natural gas emissions from natural gas-driven pneumatic controllers. All other parts of a natural gas pneumatic system will operate the same way with instrument air as they do with natural gas. The conversion of natural gas pneumatic controllers to instrument air systems is applicable to all natural gas facilities with electrical service available. Figure 6-1 illustrates a diagram of a natural gas pneumatic control system. Figure 6-2 illustrates a diagram of a compressed instrument air control system.⁸⁶

Control Effectiveness

The use of instrument air eliminates natural gas emissions from the pneumatic controllers; however, the system is only applicable in locations with access to a sufficient and consistent supply of electrical power. Instrument air systems are also usually installed at facilities where there is access to high Btu gas, a high concentration of pneumatic control valves and the presence of an operator who can ensure the system is properly functioning.⁸⁷

For natural gas processing plants, we believe that instrument air systems are typically used to power pneumatic controllers and that any natural gas-driven pneumatic controllers in use are required for safety and functional reasons. The use of an instrument air system would reduce VOC emissions from a natural gas-driven pneumatic controller by 100 percent.

Cost Impacts

Instrument air conversion requires additional equipment to properly compress and control the pressurized air. The size of the compressor depends on the number of control loops present at a location. A control loop consists of one pneumatic controller and one control valve. The volume of compressed air supply for the pneumatic system is equivalent to the volume of gas

⁸⁶ Ibid.

⁸⁷ Ibid.

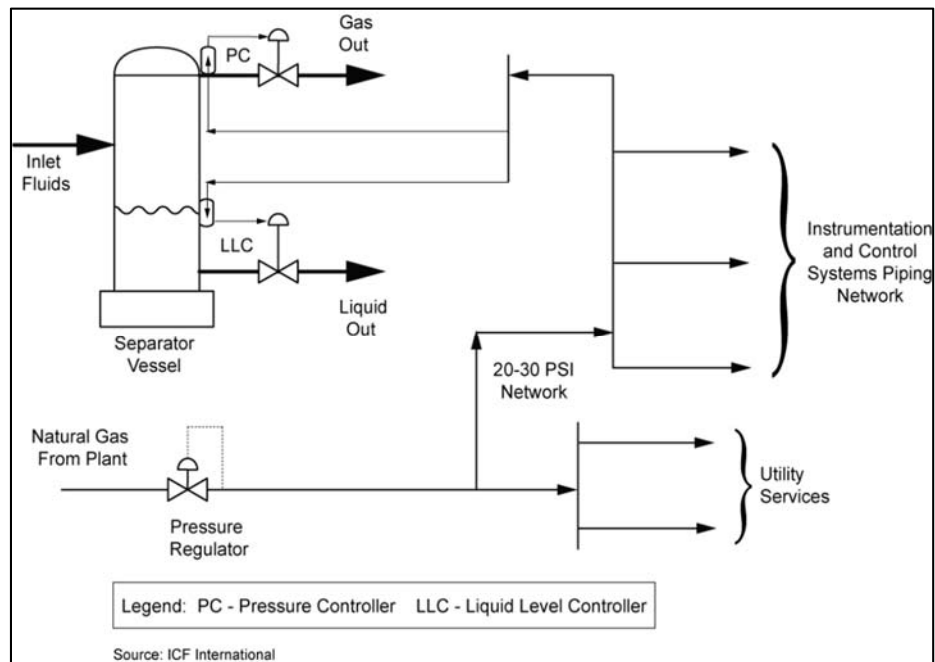


Figure 6-1. Natural Gas Pneumatic Control System

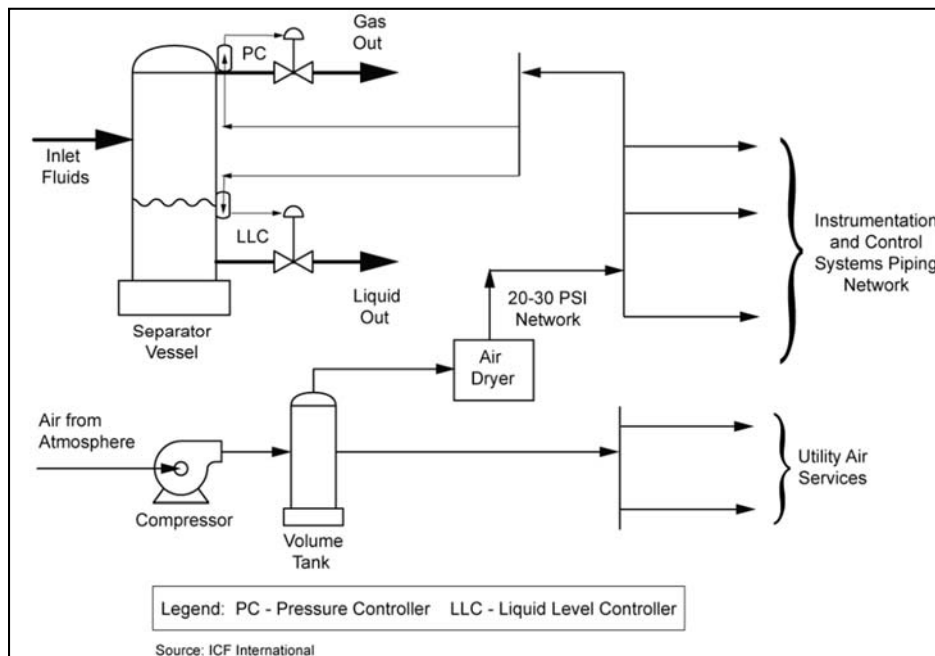


Figure 6-2. Compressed Instrument Air Control System

used to run the existing instrumentation, adjusted for air losses during the drying process. The current volume of gas usage can be determined by direct metering if a meter is installed. Otherwise, an alternative rule of thumb for sizing instrument air systems is one cubic foot per minute (cfm) of instrument air for each control loop. As the system is powered by electric compressors, the system requires a constant source of electrical power and a backup system to operate the controllers in the event of interruption of the electrical supply. Table 6-5 outlines three different sized instrument air systems including the compressor power requirements, the flow rate provided from the compressor, and the associated number of control loops.

Table 6-5. Compressor Power Requirements and Costs for Representative Instrument Air Systems^a

Compressor Power Requirements ^b			Flow Rate (cfm)	Control Loops (Loops/Compressor)	Power Costs (\$/yr)
Size of Unit	Hp	kW			
Small	10	13.3	30	15	\$7,758
Medium	30	40	125	63	\$23,332
Large	75	100	350	175	\$58,329

^a Based on rules of thumb stated in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air*. Natural Gas STAR Program. Washington, DC. 2006.

^b Power is based on the operation of two compressors operating in parallel (each assumed to be operating at full capacity 50 percent of the year).

The primary costs associated with conversion to instrument air systems are the initial capital expenditures for installing compressors and the related equipment and operating costs for electrical energy to power the compressor motor. This equipment includes a compressor, a power source, a dehydrator, gas supply piping, control instruments, valve actuators and a storage vessel. The total cost, including installation and labor, of three representative sizes of compressors were evaluated based on assumptions found in the Natural Gas STAR document, “Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air” and are summarized in Table 6-6.⁸⁸

⁸⁸ Ibid.

Table 6-6. Estimated Capital and Annual Costs of Representative Instrument Air Systems (\$2012)

Instrument Air System Size	Compressor	Tank	Air Dryer	Total Capital Cost^a	Annualized Capital Cost^b	Labor Cost	Total Annual Cost^c	Annualized Cost of Instrument Air System
Small	\$3,987	\$797	\$2,391	\$17,938	\$2,554	\$1,410	\$9,168	\$11,722
Medium	\$19,928	\$2,391	\$7,173	\$77,716	\$11,065	\$4,580	\$27,912	\$38,977
Large	\$35,071	\$4,783	\$15,941	\$143,476	\$20,428	\$6,340	\$64,669	\$85,097

^a Total Capital Cost includes the cost for two compressors, two tanks, an air dryer and installation. Installation costs are assumed to be equal to 1.5 times the cost of capital. Equipment costs were derived from the 2012 NSPS TSD.

^b These costs have been converted to 2012 dollars (from 2008 dollars) using the Federal Reserve Economic Data GDP Price Deflator (Change in GDP: Implicit Price Deflator from 2008 to 2012 (5.69 percent)).⁸⁹

^c The annualized cost was estimated using a 7 percent interest rate and 10-year equipment life. Annual cost includes the cost of electrical power, as listed in Table 6-5, and labor.

⁸⁹ U.S. Bureau of Economic Analysis. *Gross Domestic Product: Implicit Price Deflator (GDPDEF)*, retrieved from FRED, Federal Reserve Bank of St. Louis. <https://research.stlouisfed.org/fred2/series/GDPDEF/> March, 26, 2015.

For new natural gas processing plants, the cost-effectiveness of the three representative instrument air system sizes was evaluated in the 2015 NSPS Proposal TSD based on the emissions mitigated from the number of control loops the system can provide and not on a per device basis. This approach was chosen because we assume new processing plants will need to provide instrumentation for multiple control loops and size the instrument air system accordingly. Table 6-7 summarizes the natural gas processing segment cost of control per ton of VOC reduced for three sizes of representative instrument air systems. For existing natural gas processing plants, it is our understanding that these plants have already upgraded to instrument air unless the function has a specific need for a high-bleed pneumatic controller, which would most likely be safety related. The cost of converting the pneumatic controllers to instrument air includes the capital cost of \$2,000 for the ductwork and annual cost of \$285 (assuming a 10-year equipment life at 7 percent interest). The VOC cost of control for converting pneumatic controllers to instrument air for processing plants that already have instrument air ranges from \$6 to \$68 per ton of VOC removed, depending on the size of the instrument air system.

For natural gas processing, the cost of control of the three representative instrument air systems was evaluated based on the emissions mitigated from the number of control loops the system can provide and not on a per controller basis. This approach was chosen because we assume new processing plants will need to provide instrumentation for multiple control loops and size the instrument air system accordingly. We also assume that existing processing plants have already upgraded to instrument air unless the function has a specific need for a high-bleed pneumatic controller, which would most likely be safety related. Table 6-7 summarizes the natural gas processing segment cost of control per ton of VOC reduced for three sizes of representative instrument air systems.

Table 6-7. Cost of Control of Representative Instrument Air Systems in the Natural Gas Processing Segment (\$2012)

System Size	Number of Control Loops	VOC Annual Emission Reduction (tpy) ^a	Value of Product Recovered (\$2012/year) ^b	Annualized Cost of System		VOC Cost of Control (\$2012/ton)	
				Without Savings	With Savings	Without Savings	With Savings
Small	15	4.18	\$3,485	\$11,722	\$8,236	\$2,804	\$1,970
Medium	63	17.5	\$14,592	\$38,977	\$24,385	\$2,227	\$1,393
Large	175	48.7	\$40,606	\$85,097	\$44,490	\$1,747	\$914

^a Based on the emissions mitigated from the entire system, which includes multiple control loops.

^b Value of recovered product assumes natural gas processing is 82.9 percent methane by volume. A natural gas price of \$4 per Mcf was assumed.

6.3.1.3 *Electrically Powered Systems in Place of Bleed Devices*

Description

Mechanical controls have been widely used in the oil and natural gas industry. They operate using a combination of levers, hand wheels, springs and flow channels with the most common mechanical control device being a liquid-level float to the drain valve position with mechanical linkages.⁹⁰ Another device that is increasing in use is electrically powered controls. Small electrical motors (including solar powered) have been used to operate valves and have no VOC emissions. Solar-powered control systems are driven by solar-power cells that actuate mechanical devices using electric power. As such, solar cells require some type of backup power or storage to ensure reliability.

Control Effectiveness⁹¹

Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems may have difficulty handling larger flow fluctuations. Electrically powered valves are only reliable with a constant supply of electricity. These controllers can achieve a 100 percent reduction in VOC emissions where applicable.

Cost Impacts

Depending on supply of power, mechanical and solar-power system costs can range from below \$1,000 to \$10,000 for an entire system.⁹²

⁹⁰ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

⁹¹ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

⁹² U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

6.3.1.4 *Enhanced Maintenance of Natural Gas-Driven Pneumatic Controllers*

Manufacturers of pneumatic controllers indicate that emissions in the field can be higher than the reported gas consumption due to operating conditions, age and wear of the device.⁹³

Examples of circumstances or factors that can contribute to this increase include:^{94,95}

- (1) Nozzle corrosion resulting in more flow through a larger opening;
- (2) Broken or worn diaphragms, springs (e.g., spring broken that holds the supply pilot plug on its seat), bellows, fittings (e.g., leaking tubing/tubing-fittings) and nozzles;
- (3) Corrosives in the gas leading to erosion and corrosion of control loop internals;
- (4) Improper installation;
- (5) Lack of maintenance (maintenance includes replacement of the filter used to remove debris from the supply gas and replacement of O-rings and/or seals);
- (6) Lack of calibration of the controller or adjustment of the distance between the flapper and nozzle;
- (7) Foreign material lodged in the pilot seat;
- (8) Debris/deposits on vent pilot plug. Material on the vent pilot can allow the controller to exhaust gas during the activation cycle;
- (9) Debris/deposits on the supply pilot plug. Material on the supply pilot can cause the introduction of gas while the vent is open; or
- (10) Wear in the seal seat.

The EPA prepared a white paper titled “Oil and Natural Gas Sector Pneumatic Devices,” in 2014, requesting specific comment on available emissions data for pneumatic devices. One of the comments received regarding data presented in “Measurements of Methane Emissions at Natural Gas Production Sites in the United States”⁹⁶ was that the data set reported was dominated by extreme values. The commenter noted that the highest emitting controllers are simply controllers emitting at a large rate, regardless of their service or design type. These

⁹³ Ibid.

⁹⁴ Ibid.

⁹⁵ American Petroleum Institute (API). *Pneumatic Controllers*. Webinar Prepared and Presented to the U.S. Environmental Protection Agency. March 25, 2014.

⁹⁶ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Pneumatic Devices. Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel* Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at <http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf>.

controllers can have high emissions because of factors, other than design, related to maintenance, malfunction, or defect.⁹⁷

Maintenance of pneumatics can correct many of these problems and can be an effective method for reducing emissions. Cleaning and tuning, in addition to repairing leaking gaskets, tubing fittings, and seals, can save 5 to 10 scfh per device. Eliminating unnecessary valve positioners can save up to 18 scfh per device.⁹⁸

6.3.2 Existing Federal, State and Local Regulations

6.3.2.1 *Federal Regulations that Specifically Require Control of VOC Emissions*

Under the 2012 NSPS and 2016 NSPS, new or modified continuous bleed natural gas-driven pneumatic controllers at natural gas processing plants are subject to a VOC emission limit of zero (equivalent to non-natural gas-driven pneumatic controllers). Continuous bleed natural gas-driven pneumatic controllers in the production segment must have a bleed rate of 6 scfh or less.

6.3.2.2 *State and Local Regulations that Specifically Require Control of VOC Emissions*

States may have permitting restrictions on VOC emissions that apply to an emissions source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met and, often, how the source must be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

For pneumatic controllers, Colorado and Wyoming have existing control requirements similar to those required under the 2012 NSPS and 2016 NSPS. Other states have permitting and

⁹⁷ Allen, David. Comments Provided to the EPA on *Oil and Natural Gas Sector Pneumatic Devices-Peer Review Document*. University of Texas at Austin. June 2014.

⁹⁸ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

registration rules for controlling fugitive VOC emissions (which would include non-bleed emissions from pneumatic controllers).

Colorado requires that no- or low-bleed pneumatic controllers with a bleed rate of 6 scfh or less be installed for all new and existing applications (unless approved for use due to safety and/or process purposes) statewide (Regulation 7, XVIII.C.2). Where technically and economically feasible, Colorado requires no-bleed pneumatic controllers at facilities that are connected to the electric grid and using electricity to power equipment.

Wyoming requires the installation of low- or no-bleed pneumatic controllers with a bleed rate of 6 scfh or less at all new facilities. Upon modification of facilities, new pneumatic controllers must be low- or no-bleed and existing controllers must be replaced with no- or low-bleed controllers (at well site facilities only and not at natural gas processing plants).

Although some local rule requirements do not specifically require the control of VOC emissions from pneumatic controllers, local permit requirements (such as those required by the Bay Area Air Quality Management District) may require that a permit to operate applicant provide the number of high-bleed and low-bleed pneumatic devices in a permit application. Under some situations where facilities use high-bleed devices, the permitting authority might require an owner or operator to provide device-specific bleed rates and supporting documentation for each high-bleed device. In cases where high-bleed devices must be used, the permitting authority may require that the facility conduct fugitive monitoring and/or implement control requirements under conditions of their permit to operate.⁹⁹

6.4 Recommended RACT Level of Control

Sections 6.4.1 and 6.4.2 present the recommended RACT level of control for continuous bleed natural gas-driven pneumatic controllers located at natural gas processing plants and continuous bleed natural gas-driven pneumatic controllers located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline.

⁹⁹ Cheng, Jimmy. *Permit Handbook. Chapter 3.5 Natural Gas Facilities and Crude Oil Facilities*. Bay Area Air Quality Management District. September 16, 2013.

6.4.1 Continuous Bleed Natural Gas-Driven Pneumatic Controllers Located at a Natural Gas Processing Plant

Based on our evaluation of available data obtained in the development of the 2012 NSPS and 2016 NSPS, peer review comments received on the “Oil and Natural Gas Sector Pneumatic Devices” white paper, and existing regulations that control VOC emissions from pneumatic controllers, we recommend that VOC emissions from an individual continuous bleed natural gas-driven pneumatic controller located at a natural gas processing plant be controlled by RACT. As noted in section 6.3.2, both Colorado and Wyoming require either low- or no-bleed controllers (where a high-bleed controller is defined as emitting at least 6 scfh); and the 2012 NSPS and 2016 NSPS require that new and modified individual continuous bleed pneumatic controllers at natural gas processing plants have a natural gas bleed rate of 0 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 0 scfh). For existing individual continuous bleed pneumatic controllers at natural gas processing plants, our RACT recommendation is that controllers have a natural gas bleed rate of 0 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 0 scfh). Our rationale for selecting a natural gas bleed rate of 0 scfh (with functional and safety exceptions) for our recommended RACT is based on the ability of most natural gas processing plants to install and utilize an instrument air system. As discussed in section 6.3.1.2 of this chapter, by using an instrument air system, compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic controller. Therefore, the use of instrument air eliminates natural gas and VOC emissions from pneumatic controllers and supports a natural gas bleed rate of 0 scfh.

In order to meet an emission limit of 0 scfh, natural gas processing plants would likely need to use an instrument air system. The use of instrument air eliminates natural gas and VOC emissions from natural gas-driven pneumatic controllers. We believe that most natural gas processing plants already meet the recommended RACT level of control by driving controllers with instrument air or other non-gas-driven controls unless there is a specific need for a high-bleed pneumatic controller. Nonetheless, for those natural gas processing plants that do not have an installed instrument air system, the cost of control of installing three representative instrument air systems was evaluated under the 2012 NSPS and 2016 NSPS based on the emissions

mitigated from the number of control loops the system can provide (see section 6.3.1.2 of this chapter). Based on this analysis, the cost of this option was considered to be reasonable for natural gas processing plants (see Table 6-7 of section 6.3.1.2 of this chapter). The cost of control per ton of VOC reduced was estimated at \$1,700 - \$2,800 without savings and \$910 - \$2,000 with savings. For determining potential cost impacts, a major assumption made was that processing plants are constructed at locations with sufficient electrical service to power the instrument air compression systems.

In summary, we recommend the following RACT for each continuous bleed natural gas-driven pneumatic controller located at a natural gas processing plant:

RACT for Each Continuous Bleed Natural Gas-Driven Pneumatic Controller Located at a Natural Gas Processing Plant:¹⁰⁰ Each continuous bleed natural gas driven pneumatic controller located at a natural gas processing plant must have a natural gas bleed rate of 0 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 0 scfh).

6.4.2 Continuous Bleed Natural Gas-Driven Pneumatic Controllers Located from the Wellhead to the Natural Gas Processing Plant or Point of Custody Transfer to an Oil Pipeline

Based on our evaluation of available data obtained in the development of the 2012 NSPS and 2016 NSPS, peer review comments received on the “Oil and Natural Gas Sector Pneumatic Devices” white paper, and existing regulations that control VOC emissions from pneumatic controllers, we are recommending a natural gas bleed rate less than or equal to 6 scfh with limited exceptions described below as the RACT for controlling VOC emissions from continuous bleed natural gas-driven pneumatic controllers located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline. We are also recommending that no requirements apply under RACT for pneumatic controllers that have a natural gas bleed rate less than or equal to 6 scfh that are located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline.

¹⁰⁰ In the NSPS, we excluded from the NSPS affected facility status non-natural gas-driven pneumatic controllers located at natural gas processing plants. Natural gas-driven controllers exempt from the zero VOC emission standard under the functional needs exclusion would still be affected facilities and would have certain tagging, recordkeeping and reporting requirements.

As indicated in section 6.2.2 of this chapter, low-bleed pneumatic controllers can emit up to 6 scfh. Both Colorado and Wyoming conditionally require either low- or no-bleed controllers (where a high-bleed controller is defined as emitting greater than 6 scfh); and the 2012 NSPS and 2016 NSPS require that new and modified individual continuous bleed pneumatic controllers have a bleed rate of 6 scfh or less (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh). For purposes of this CTG, and consistent with the definition of high-bleed controller used for the 2012 NSPS, 2016 NSPS, and both the Wyoming and Colorado state regulations, a high-bleed pneumatic device is defined as emitting greater than 6 scfh to the atmosphere.

Although both Wyoming and Colorado specifically require low-bleed or no-bleed pneumatic controllers in place of high-bleed controllers (where technically and economically feasible), we are recommending a RACT emission limit of 6 scfh (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh) apply to each continuous bleed pneumatic controller. This approach allows flexibility in how a source chooses to limit VOC emissions from an applicable individual pneumatic controller and acknowledges that there may be circumstances where it is not practical to meet a 6 scfh limit. By requiring a limit be met, facilities have the option of controlling emissions by one or more options presented in section 6.3.1 of this chapter (e.g., replace a high-bleed device with a low-bleed device and implement enhanced monitoring to mitigate increased VOC emissions from poor maintenance/poor operation) depending on site-specific circumstances. We are including this flexibility in our recommended RACT to address the varied control options and applicability issues (e.g., instrument air systems require access to electrical power or a backup pneumatic controller and access to electric power or backup pneumatic controllers may not be available in remote locations) presented in section 6.3.1 of this chapter.

Although facilities would have flexibility in how they meet the recommended RACT level of control, by establishing an emission limit equal to the design bleed rate for a low-bleed device (6 scfh), we believe that most facilities would likely replace high-bleed controllers with low-bleed controllers (it is assumed about 80 percent of high-bleed devices can be replaced with

low-bleed devices).¹⁰¹ For the production segment, we estimated that, on average, 1.41 tons of VOC would be reduced annually per device in the production segment from installing a low-bleed device in place of a high-bleed device.

As presented in section 6.3.1.1 of this chapter, the cost of replacing a high-bleed device with a new low-bleed device is on the order of \$2,698 per device, and the cost of control in the production segment is estimated to be \$210 per ton of VOC emissions reduced without savings. Considering the cost savings of gas recovered from installing a low-bleed device in place of a high-bleed device, it is estimated that there would be an overall net savings.

In summary, we recommend the following RACT for each single continuous bleed natural gas-driven pneumatic controller located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline:

RACT for Each Single Continuous Bleed Natural Gas-Driven Pneumatic Controller Located from the Wellhead to the Natural Gas Processing Plant or Point of Custody Transfer to an Oil Pipeline: Each pneumatic controller, which is a single continuous bleed natural gas-driven pneumatic controller¹⁰² must have a natural gas bleed rate less than or equal to 6 scfh (unless there are functional needs including, but not limited to response time, safety and positive actuation, requiring a bleed rate greater than 6 scfh).

¹⁰¹ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

¹⁰² In the NSPS, we excluded from NSPS pneumatic controller affected facility status continuous bleed natural gas-driven pneumatic controllers with a bleed rate not greater than 6 scfh (low-bleed controllers) located in the production segment. Continuous bleed natural gas-driven controllers exempt from the 6 scfh bleed rate emission standard under the functional needs exclusion would still be affected facilities and would have certain tagging, recordkeeping and reporting requirements.

6.5 Factors to Consider in Developing Pneumatic Controller Compliance Procedures

6.5.1 Oil and Natural Gas Production (Individual Continuous Bleed Pneumatic Controller with a Natural Gas Bleed Rate Greater than 6 scfh Located from the Wellhead to the Natural Gas Processing Plant or Point of Custody Transfer to an Oil Pipeline)

To ensure that each continuous bleed natural gas-driven pneumatic controller located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline is operated with a natural gas bleed rate less than or equal to 6 scfh (the recommended RACT level of control), we recommend that regulating agencies specify operating, recordkeeping and reporting requirements to document compliance. It is recommended that air agencies require that each pneumatic controller be tagged with the month and year of installation and identification information that allows traceability to manufacturer's documentation.

It is recommended that air agencies require owners and operators of continuous bleed natural gas-driven pneumatic controllers that are subject to RACT maintain records that: (1) document the location and manufacturer's specifications of each pneumatic controller; (2) if applicable, provide a demonstration as to why the use of a pneumatic controller with a natural gas bleed rate greater than 6 scfh is required (the recommended RACT level of control); and (3) document deviations in cases where a pneumatic controller was not operated in compliance with RACT.

It is also recommended that air agencies require owners and operators to submit annual reports that include (1) if applicable, documentation that the use of a pneumatic controller with a natural gas bleed rate greater than 6 standard cubic feet per hour is required and the reasons why; and (2) the records of deviations that occurred during the reporting period.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

6.5.2 Natural Gas Processing Segment (Individual Continuous Bleed Natural Gas-Driven Pneumatic Controller Located at a Natural Gas Processing Plant)

To ensure each continuous bleed natural gas-driven pneumatic controller at natural gas processing plants is operated with a natural gas bleed rate of zero (the recommended RACT level of control), we suggest that air agencies specify operating, recordkeeping and reporting requirements to document compliance. We also suggest that air agencies require that each pneumatic controller be tagged with the month and year of installation and identification information that allows traceability to the manufacturer's documentation. It is recommended that air agencies require owners and operators of pneumatic controllers maintain records that:

- (1) document the location and manufacturer's specifications of each pneumatic controller;
- (2) document that the natural gas bleed rate is zero; and (3) document deviations in cases where a pneumatic controller was not operated in compliance with RACT.

It is also recommended that air agencies require owners and operators to submit annual reports that include the records of deviations that occurred during the reporting period.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

7.0 PNEUMATIC PUMPS

The oil and natural gas industry uses a variety of pneumatic gas-driven pumps where there is no reliable electrical power to “control processing problems and protect equipment.”¹⁰³ Pneumatic pumps are “small positive displacement, reciprocating units used throughout the oil and natural gas industry to inject precise amounts of chemicals into process streams or for freeze protection glycol circulation.”¹⁰⁴ Most chemical injection pumps fall into two main types: (1) diaphragm pumps, generally used for heat tracing; or (2) plunger/piston, generally used for chemical and methanol injection. Pneumatic pumps driven by natural gas emit natural gas, which contains VOC. Other types of pneumatic pumps may be driven by gases other than natural gas and, therefore, do not emit VOC. The focus of this CTG is natural gas-driven pneumatic pumps. This chapter provides a description of pneumatic pumps that are used in the oil and natural gas industry, including their function and associated emissions. This chapter also provides control techniques used to reduce VOC emissions from pneumatic pumps, along with costs and emission reductions. Finally, this chapter provides a discussion of our recommended RACT for pneumatic pumps and the associated VOC emission reductions and costs.

7.1 Applicability

For the purposes of this CTG, a pneumatic pump is a positive displacement reciprocating unit used for injecting precise amounts of chemicals into a process stream or for glycol circulation. The pneumatic pump may use natural gas or another gas to drive the pump. The emissions and emission control options discussed herein would apply to natural gas-driven chemical/methanol and diaphragm pumps located at natural gas processing plants and well sites.

¹⁰³ U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 13: Chemical Injection Pumps*. EPA-600/R-96-080b. June 1996.

¹⁰⁴ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

7.2 Process Description and Emission Sources

7.2.1 Process Description

As noted above, pneumatic pumps are “positive displacement, reciprocating units used for injecting precise amounts of chemicals into a process stream or for glycol circulation.”¹⁰⁵ Pneumatic pumps often make use of gas pressure where electricity is not readily available.¹⁰⁶ In the production segment, the supply gas is mostly produced natural gas, whereas in the processing segment, the supply gas may be compressed air. For natural gas-driven pneumatic pumps, characteristics that affect VOC emissions include the frequency of operation, the size of the unit, the supply gas pressure, and the inlet natural gas composition.¹⁰⁷

Pneumatic pumps are generally used for one of three purposes: glycol circulation in dehydrators, hot oil circulation for heat tracing/freeze protection, or chemical injection. Glycol dehydrator pumps may recover energy from the high-pressure rich glycol/gas mixture leaving the absorber and use that energy to pump the low-pressure lean glycol back into the absorber.¹⁰⁸ Diaphragm pumps are commonly used to circulate hot glycol or other heat-transfer fluids in tubing covered with insulation to prevent freezing in pipelines, vessels, and tanks. Chemical injection pumps (i.e., piston/plunger pumps or small diaphragm pumps) inject small amounts of chemicals, such as methanol, to prevent hydrate formation or corrosion inhibitors into process streams to regulate operations of a plant and protect the equipment.

Pneumatic pumps have two major components, a driver side and a motive side, which operate in the same manner but with different reciprocating mechanisms. Pressurized gas provides energy to the driver side of the pump, which operates a piston or flexible diaphragm to draw fluid into the pump. The motive side of the pump delivers the energy to the fluid being moved in order to discharge the fluid from the pump. The natural gas leaving the exhaust port of

¹⁰⁵ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

¹⁰⁶ Ibid.

¹⁰⁷ Ibid.

¹⁰⁸ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Pneumatic Devices. Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel*. Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at <http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf>.

the pump is either directly discharged into the atmosphere or is recovered and used as a fuel gas or stripping gas.¹⁰⁹

Chemical injection pumps are positive displacement, reciprocating units designed to inject precise amounts of chemical into a process stream. Positive displacement pumps work by allowing a fluid to flow into an enclosed cavity from a low-pressure source, trapping the fluid, and then forcing it out into a high-pressure receiver by decreasing the volume of the cavity. A complete reciprocating stroke includes two movements, referred to as an upward motion or suction stroke, and a downward motion or power stroke. During the suction stroke, the chemical is lifted through the suction check valve into the fluid cylinder. The suction check valve is forced open by the suction lift produced by the plunger and the head of the liquid being pumped. Simultaneously, the discharge check valve remains closed, thus allowing the chemical to remain in the fluid chamber. During the power stroke, the plunger assembly is forced downwards, immediately shutting off the suction check valve. Simultaneously, the chemical is displaced, forcing open the discharge check valve and allowing the fluid to be discharged.¹¹⁰

Typical chemicals injected in an oil or natural gas field are biocides, demulsifiers, clarifiers, corrosion inhibitors, scale inhibitors, hydrate inhibitors, paraffin dewaxers, surfactants, oxygen scavengers, and H₂S scavengers. These chemicals are normally injected at the wellhead and into gathering lines or at production separation facilities. Because the injection rates are typically small, the pumps are also small. They are often attached to barrels containing the chemical being injected.¹¹¹

Diaphragm pumps are positive displacement pumps, meaning they use contracting and expanding cavities to move fluids. Diaphragm pumps work by flexing the diaphragm out of the displacement chamber. When the diaphragm moves out, the volume of the pump chamber increases and causes the pressure within the chamber to decrease and draw in fluid. The inward stroke has the opposite effect, decreasing the volume and increasing the pressure of the chamber to move out fluid.¹¹²

¹⁰⁹ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

¹¹⁰ Ibid.

¹¹¹ Ibid.

¹¹² GlobalSpec. *Diaphragm Pumps Information*. Available online - http://www.globalspec.com/learnmore/flow_transfer_control/pumps/diaphragm_pumps.

Not all pneumatic pumps are natural gas driven. At sites without electrical service sufficient or reliable enough to power an instrument air compressor control system, mechanical or electrically powered pneumatic pumps may be used. Where reliable electrical service is available, sources of power other than pressurized natural gas, such as compressed instrument air may be used. Because these devices are not natural gas driven, they do not directly release natural gas or VOC emissions. Instrument air systems are feasible only at oil and natural gas industry locations where the devices can be driven by compressed instrument air systems and have electrical service sufficient and reliable enough to power a compressor. This analysis assumes that natural gas processing plants are likely to have electrical service sufficient to power an instrument air system, and that most existing gas processing plants use instrument air instead of natural gas-driven pumps.¹¹³ The application of electrical controls is discussed further in section 7.3 of this chapter.

7.2.2 Emissions Data

7.2.2.1 Summary of Major Studies and Emissions

In the evaluation of the emissions from pneumatic pumps and the potential options available to reduce these emissions, numerous studies were consulted. Table 7-1 lists these references with an indication of the type of relevant information contained in each reference. In addition to these sources, we evaluated the peer reviewer and public comments received on the EPA's white paper, "Oil and Natural Gas Sector Pneumatic Devices."¹¹⁴

¹¹³ U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices*. EPA-600/R-96-080k. June 1996.

¹¹⁴ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Pneumatic Devices. Report for Oil and Natural Gas Sector Pneumatic Devices Review Panel*. Office of Air Quality Planning and Standards (OAQPS). April 2014. Available at <http://www.epa.gov/airquality/oilandgas/2014papers/20140415pneumatic.pdf>.

Table 7-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options ^g
Greenhouse Gas Reporting Program ^a	EPA	2014	Nationwide	X	
Inventory of Greenhouse Gas Emissions and Sinks ^b	EPA	Annual	Nationwide/ Regional	X	
Methane Emissions from the Natural Gas Industry ^{c,d}	EPA/GRI	1996	Nationwide	X	
Methane Emissions from the Petroleum Industry ^e	EPA	1999	Nationwide	X	
Natural Gas STAR Program ^f	EPA	2012	Study Specific	X	X

^a U.S. Environmental Protection Agency. *Greenhouse Gas Reporting Program*. Washington, DC. November 2014.

^b U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. <https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html>.

^c U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report*. EPA-600/R-96-080b. June 1996; U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology*. EPA-600/R-96-080c. June 1996.

^d U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors*. EPA-600/R-96-080e. June 1996; and U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 12: Pneumatic Devices*. EPA-600/R-96-080k. June 1996.

^e U.S. Environmental Protection Agency. *Methane Emissions from the U.S. Petroleum Industry. Final Report*. Prepared for the U.S. Environmental Protection Agency by Radian International LLC. EPA-600/R-99-010. February 1999.

^f U.S. Environmental Protection Agency. *Lessons Learned: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR. Washington, DC. October 2006.

^g An “X” in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

7.2.2.2 Representative Pneumatic Pump Emissions

For this analysis, we consulted information in the appendices of Natural Gas STAR lessons learned documents on pneumatic pumps,^{115,116} the GHGRP, the GHG Inventory, and

¹¹⁵ U.S. Environmental Protection Agency. *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas STAR. Washington, DC. October 2006.

¹¹⁶ U.S. Environmental Protection Agency. Pro Fact Sheet No. 301. *Convert Pneumatics to Mechanical Controls*. Office of Air and Radiation: Natural Gas STAR. Washington, DC. September 2004.

U.S. EPA/GRI Report.¹¹⁷ The GHGRP and GHG Inventory use emission factors from the U.S. EPA/GRI Report. Similarly, we determined that the best available emission factors for pneumatic pumps are presented in the U.S. EPA/GRI Report.

The basic approach used for this analysis was to first approximate methane emissions from the average pneumatic pump in the production and processing segments and then estimate VOC and HAP emissions using the gas composition factors from the 2011 Gas Composition Memorandum. The specific gas composition ratio used for this analysis was 0.278 lbs VOC per pound methane in the production and processing segment. Table 7-2 summarizes the estimated average emission factors for a representative pneumatic pump for the production and processing segments for both methane and VOC.

Table 7-2. Average Emission Estimates per Pneumatic Device

Segment/Pump Type	Emission Factor Methane (scf/day) ^a	Emission Factor Methane (Mcf/yr) ^b	Emission Factor Methane (tpy) ^c	Emission Factor VOC (tpy) ^d
Production				
Diaphragm	446	163	3.46	0.96
Piston	48.9	18	0.38	0.11
Processing				
Small Diaphragm	446	163	3.46	0.96
Medium Diaphragm	446	163	3.46	0.96
Large Diaphragm	446	163	3.46	0.96
Small Piston	48.9	18	0.38	0.11
Medium Piston	48.9	18	0.38	0.11
Large Piston	48.9	18	0.38	0.11

^a Data Source: EPA/GRI. *Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps*. June 1996 (EPA-600/R -96-080m), Sections 5.1 – Diaphragm Pumps and 5.2 – Piston Pumps.

^b Assumes 365 days/yr operation in natural gas production and processing.

^c Assumes density of methane is 19.26 g/scf.

^d Assumes 0.278 VOC content per pound of methane.

¹¹⁷ Gas Research Institute (GRI)/U.S. Environmental Protection Agency. *Research and Development, Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps*. June 1996 (EPA-600/R -96-080m).

7.3 Available Controls and Regulatory Approaches

7.3.1 Available VOC Emission Control Options

Natural gas-driven pneumatic pumps emit VOC emissions as part of their normal operation. Depending on the type of pump and the constraints of the location, companies can utilize a variety of technologies that have been developed over the years. In situations where the replacement of natural gas-driven pumps with electric, solar and instrument air pumps is not feasible, emissions can be captured and routed to a VRU or to a combustion device.

Sections 7.3.1.1 and 7.3.1.2 discuss the control of VOC emissions by replacing natural gas-driven pumps with solar pumps and electric pumps. Section 7.3.1.3 discusses the use of an instrument air system to drive the pneumatic pump in order to eliminate VOC emissions. Lastly, section 7.3.1.4 discusses reducing VOC emissions by routing emissions from the pump to a combustion device, and section 7.3.1.5 discusses capturing VOC emissions using a VRU.

7.3.1.1 *Solar Pumps*

Description

Solar pumps provide the same functionality as natural gas-driven pumps and can be utilized at remote sites where electricity is not available. However, peer review comments received on the EPA's white paper "Oil and Natural Gas Sector Pneumatic Devices" noted that they predominantly operated solar-powered pneumatic pumps for chemical injection and the pumps failed as early as after two to three cloudy days due to insufficient battery charge.¹¹⁸ When solar pumps are properly charged, a solar-charged DC pump can handle a range of throughputs up to 100 gallons per day with maximum injection pressure around 3,000 psig and have no VOC emissions. Converting natural gas-driven chemical pumps can reduce methane emissions by an estimated 3.46 tpy per diaphragm pump and 0.38 tpy per piston pump for all segments of the oil and natural gas industry.¹¹⁹ Based on the gas composition for natural gas in the production segment, we estimate that replacement of a pneumatic pump with a solar-powered pump will reduce VOC emissions by 0.96 tpy per diaphragm pump and 0.11 tpy for a piston pump.

¹¹⁸ Reese, Carrie, Environmental Compliance Manager. Comments on the Oil and Natural Gas Sector Pneumatic Devices. Pioneer Natural Resources.

¹¹⁹ U.S. Environmental Protection Agency. PRO Fact Sheet No. 202. *Convert Natural Gas-Driven Chemical Pumps*.

Control Effectiveness

Replacing a natural gas-driven pump with a solar pump can result in 100 percent reduction in VOC emissions and is feasible in regions where there is sufficient sunlight to power the pump, and backup power is not required. Although, as stated above, solar-powered pumps are capable of pumping up to 100 gallons per day, they are typically used for low volume applications to inject methanol or corrosion inhibitors into a well with typical volumes ranging from 6 to 8 gallons per day. In addition to the low volume pumps, large volume pumps used to replace natural gas-assisted circulation pumps for glycol dehydrators can also be converted to solar.

Cost Impacts

The primary costs associated with conversion to solar pumps are the initial capital expenditures. Solar pumps generally have low maintenance costs, which are typically lower than natural gas-driven pump maintenance costs. The cost being attributed to the replacement of pneumatic pumps with solar-powered pumps includes the capital cost of the pump and its associated operating costs. The operating costs are estimated to be 10 percent of the capital cost. Based on the Natural Gas STAR document, "PRO Fact Sheet: Convert Natural Gas-Driven Chemical Pumps,"¹²⁰ the capital (purchase) cost for a solar-powered electric pump is approximately \$2,000 with solar panels having a lifespan of 15 years and electric motors lasting 5 years. The total capital cost, including installation and labor is \$2,227 (2012 dollars). We estimate there would be no additional annual operating costs for solar pumps above and beyond that of ordinary field personnel duties. Annualized over the life of the pump at a 7 percent discount rate, the annualized cost of replacing a pneumatic pump with a solar pump is \$317. In addition, the use of solar pumps will have savings realized from the natural gas not released. We estimate that each diaphragm pump replaced will save 197 Mcf per year of natural gas from being emitted and each piston pump will have a natural gas savings of 22 Mcf per year. The value of the natural gas saved based on \$4.00 per Mcf would be \$786 per year per diaphragm pump and \$87 per year per piston pump.

¹²⁰ U.S. Environmental Protection Agency. PRO Fact Sheet No. 202. *Convert Natural Gas-Driven Chemical Pumps*.

7.3.1.2 *Electric Pumps*

Description

Electric pumps provide the same functionality as natural gas-driven pumps, and are only restricted by the use of reliable power. Electric pumps have no VOC emissions, and converting a natural gas-driven pneumatic pump to an electric pump can reduce VOC emissions by an estimated 0.96 tpy per diaphragm pump and 0.11 tpy per piston pump.

Control Effectiveness

Replacing a natural gas-driven pump with an electric pump can result in 100 percent reduction in VOC emissions. However, use of electric pumps requires a sufficient and reliable source of electricity. These pumps are, therefore, more common at natural gas processing plants or large dehydration facilities that have access to reliable electric power.

Cost Impacts

The primary costs associated with converting natural gas-driven pumps to electric pumps are the initial capital expenditures, installation and ongoing operation and maintenance. Based on the Natural Gas STAR document, “PRO Fact Sheet: Convert Natural Gas-Driven Chemical Pumps,”¹²¹ the cost of an electric pump to replace a diaphragm pump is \$4,647 and to replace a piston pump is \$1,819 in 2012 dollars depending on the horsepower of the unit.¹²² The annual operating costs for an electric pump are estimated to be \$293. Based on these costs annualized over the life expectancy of the pump at a 7 percent discount rate, the annualized cost for an electric pump to replace a diaphragm pump is \$954, and \$552 to replace a piston pump. In addition, the use of electric pumps will have savings realized from the natural gas not released. We estimate that each diaphragm pump replaced will save 197 Mcf per year of natural gas from being emitted and each piston pump will have a natural gas savings of 22 Mcf per year. The value of the natural gas saved based on \$4.00 per Mcf would be \$786 per year per diaphragm pump and \$87 per year per piston pump.

¹²¹ Ibid.

¹²² U.S. Environmental Protection Agency. *Lessons Learned. Replacing Gas-Assisted Glycol Pumps with Electric Pumps*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. 2006. October 2006.

7.3.1.3 *Instrument Air System*

Description

Instrument air systems require a compressor, power source, dehydrator, and volume tank. The same pneumatic pumps can be used for natural gas and compressed air, without altering any of the parts of the pneumatic pump, but instrument air eliminates the emissions of natural gas. All facilities that have access to an adequate and reliable source of electricity can install an instrument air system. The following, taken from the Natural Gas STAR document, “PRO Fact Sheet: Convert Gas Pneumatic Controls to Instrument Air,”¹²³ describes the major components of an instrument air system:

- (1) Compressors used for instrument air delivery are available in various types and sizes, from rotary screw (centrifugal) compressors to positive displacement (reciprocating piston) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical emission rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank. For reliability, a full spare compressor is normally installed.
- (2) A critical component of the instrument air control system is the power source required to operate the compressor. Because high-pressure natural gas is abundant and readily available, natural gas-driven pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and remote locations, however, a reliable source of electric power can be difficult to ensure. In some instances, solar-powered, battery-operated air compressors can be feasible for remote locations, which would both reduce VOC emissions and energy consumption. Small natural gas-powered fuel cells are also being developed.

¹²³ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Convert Gas Pneumatic Controls to Instrument Air*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

- (3) Dehydrators, or air dryers, are an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.
- (4) The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high-pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools, without affecting the process control functions.

Control Effectiveness

Instrument air eliminates all emissions from natural gas-driven pneumatic pumps, but can only be utilized in locations with sufficient and reliable electrical power. Furthermore, instrument air systems are more economical and, therefore, more common at facilities with a high concentration of pneumatic devices and where an operator can ensure the system is properly functioning.¹²⁴ Because all emissions can be avoided by converting natural gas-driven chemical pumps to instrument air, methane emissions can be reduced by an estimated 3.46 tpy per diaphragm pump and 0.38 tpy per piston pump. Based on the gas composition for natural gas in the production segment, we estimate that converting a natural gas-driven pneumatic pump to instrument air will reduce VOC emissions by 0.96 tpy per diaphragm pump and 0.11 tpy per piston pump.

Cost Impacts

As stated previously, instrument air conversions require a compressor with a capacity based on the number of control loops at the location. The compressor size is equivalent to the volume of gas used by the control loops after adjusting for gas losses during drying, plus any utility air necessary at the facility. This volume can either be calculated via a meter or utilizing a rule of thumb of one cubic foot per minute (cfm) of instrument air per control loop.¹²⁵

The costs associated with instrument air systems are primarily capital costs for the compressor(s), air dryer and the volume tank, but also include operational costs for electricity to

¹²⁴ Ibid.

¹²⁵ U.S. Environmental Protection Agency. Lessons Learned from Natural Gas STAR Partners. *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. Office of Air and Radiation: Natural Gas STAR Program. Washington, DC. October 2006.

drive the compressor motor. Other components of the instrument air system, including piping, control instruments and valve actuators, would already be in place for a gas system. We assume that existing processing plants have an instrument air system in place, including backup systems, and that the cost of increasing air load on the system would be confined to the incremental cost associated with upgrading or replacing the compressor and connecting the pumps to the system. The size of the compressor required would depend on the additional air load required for the instrument air system to handle the pneumatic pumps. Table 7-3 summarizes cost estimates to replace various size compressors in an existing instrument air system.

Table 7-3. Cost of Compressor Replacement for Existing Instrument Air System (\$2012)

Compressor Size	Total Capital Cost ^a	Annualized Cost ^b	Total O&M Cost ^c	Annual Cost ^d
Small	\$5,999	\$854	\$9,197	\$10,051
Medium	\$29,989	\$4,270	\$28,002	\$32,271
Large	\$52,779	\$7,515	\$64,880	\$72,394

^a 2016 NSPS TSD.

^b Annualized capital cost using a 7 percent interest rate and an equipment life of 10 years.

^c The total O&M includes both the annual labor cost and the annual power cost.

^d The total annual cost includes the annualized capital cost and the total O&M cost.

7.3.1.4 Route Emissions to an Existing or New Combustion Device

Description

Typical combustion devices used in the oil and natural gas industry to control VOC emissions and their control efficiency are discussed in greater detail in section 4.3.1.2 of chapter 4 of this document. It is assumed that most processing plants and large dehydration facilities have at least one existing combustion device onsite.

Control Effectiveness

Routing emissions from a natural gas-driven pump to an existing combustion device, or a newly installed combustion device does not reduce the volume of natural gas discharged from the pump, but rather combusts the gas. Based on the gas composition for natural gas in the production segment, we estimated that routing emissions to a combustion device would reduce VOC emissions by an estimated 0.91 tpy per diaphragm pump and 0.1 tpy per piston pump.

Cost Impacts

Routing natural gas to an existing combustion device or installing a new combustion device have associated capital and operating costs. Based on costs for a combustion device provided in the 2015 NSPS TSD, the capital cost for installing a new combustion device to control emissions is estimated to cost \$34,250 and the annual operating cost is \$17,001 in 2012 dollars. Based on the life expectancy for a combustion device, we estimate the annualized cost of installing a new combustion device to be approximately \$21,877, using a 7 percent discount rate. The capital cost for routing emissions to an existing control device to control emissions is estimated to be \$5,433 with an annualized cost of \$774, using a 7 percent discount rate. Because the natural gas captured is combusted there is no gas savings associated with the use of a combustion device to reduce VOC emissions. Table 7-4 presents the estimated VOC cost of control for routing natural gas-driven pump emissions to an existing combustion device. Table 7-5 presents the cost of control for routing natural gas-driven pump emissions to a new combustion device.

Table 7-4. VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to an Existing Combustion Device

Pump Type/ Segment	VOC Emission Reductions (tpy/pump)	Annualized Cost (\$2012)	VOC Cost of Control (\$2012/ton)
<i>Diaphragm Pumps</i>			
Production	0.91	\$774	\$847
Processing	0.91	\$774	\$847
<i>Piston Pumps</i>			
Production	0.10	\$774	\$7,709
Processing	0.10	\$774	\$7,709

Table 7-5. VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to a New Combustion Device

Pump Type/ Segment	VOC Emission Reductions (tpy/pump)	Annualized Cost (\$2012)	VOC Cost of Control (\$2012/ton)
<i>Diaphragm Pumps</i>			
Production	0.91	\$21,877	\$23,944
Processing	0.91	\$21,877	\$23,944
<i>Piston Pumps</i>			
Production	0.10	\$21,877	\$218,017
Processing	0.10	\$21,877	\$218,017

7.3.1.5 *Route Emissions to a Vapor Recovery Unit (VRU)*

Description

Vapor recovery units capture low-pressure vapor streams, increase the pressure by means of a compressor, and then route the vapor stream to a process or other useful purpose. These systems typically include a backup compressor system to allow for shutdowns and repairs. Vapor recovery units are more economical for facilities with multiple natural gas emission sources that can be routed to the VRU. Some of these other emission sources can include tanks, dehydrators, and compressors and as a result, VRUs are more common at natural gas processing plants. Vapor recovery units are discussed in greater detail in section 4.3.1.1 of chapter 4 of this document.

Control Effectiveness

Use of a vapor recovery technology has the potential to reduce the VOC emissions from natural gas-driven pumps by 100 percent if all vapor is recovered. We recognize that VRUs may not continuously meet this efficiency in practice. Therefore, we estimate that routing emissions from a natural gas-driven pump to an existing or newly installed VRU can reduce the VOC emitted by approximately 95 percent (accounting for any reduced efficiency that may occur) while, at the same time, capturing the natural gas for beneficial use. We estimate that methane emission reductions for routing gas to a VRU to be 3.29 tpy for a diaphragm pump and 0.36 tpy for a piston pump. Based on the gas composition for natural gas in the production segment, we

estimate that routing emissions to a VRU can reduce VOC emissions by 0.91 tpy per diaphragm pump and 0.1 tpy per piston pump.

Cost Impacts

Based on costs for a VRU provided in the 2015 NSPS TSD, we estimate the capital cost of installing a VRU to be \$104,111 and the annual operation and maintenance cost to be \$9,932 in 2012 dollars. The total annualized cost of a new VRU is estimated to be \$24,755 based on a 7 percent discount rate.

If a VRU is already onsite, then the additional costs for routing emissions from a pump are small, as the majority of costs are piping. We estimated the cost of routing emissions to an existing VRU to be \$5,433 in 2012 dollars. The annualized cost of routing natural gas emissions to an existing VRU is estimated to be \$774 based on a 7 percent discount rate. In addition, there is potential for beneficial use of natural gas recovered through the VRU. We estimated the annual natural gas recovered to be 187 Mcf per year per diaphragm pump and 21 Mcf per year per piston pump. The resulting natural gas savings is estimated to be \$749 per diaphragm pump and \$84 per piston pump, per year based on a value of \$4.00 per Mcf of natural gas recovered. Table 7-6 presents the estimated VOC cost of control for routing natural gas-driven pump emissions to an existing VRU. Table 7-7 presents the estimated VOC cost of control for routing gas-driven pump emissions to a new VRU.

Table 7-6. VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to an Existing VRU

Pump Type/ Segment	VOC Emission Reductions (tpy/pump)	Annualized Cost (\$2012)	VOC Cost of Control (\$2012/ton)	
			Without savings	With savings
Diaphragm Pumps				
Production	0.91	\$774	\$847	\$27
Processing	0.91	\$774	\$847	\$27
Piston Pumps				
Production	0.10	\$774	\$7,709	\$6,876
Processing	0.10	\$774	\$7,709	\$6,876

Table 7-7. VOC Cost of Control for Routing Natural Gas-Driven Pump Emissions to a New VRU

Pump Type/ Segment	VOC Emission Reductions (tpy/pump)	Annualized Cost (\$2012)	VOC Cost of Control (\$2012/ton)	
			Without savings	With savings
Diaphragm Pumps				
Production	0.91	\$24,755	\$27,094	\$26,275
Processing	0.91	\$24,755	\$27,094	\$26,275
Piston Pumps				
Production	0.10	\$24,755	\$246,697	\$245,864
Processing	0.10	\$24,755	\$246,697	\$245,864

7.3.2 Existing Federal, State and Local Regulations

7.3.2.1 *Federal Regulations that Specifically Require Control of VOC Emissions*

The EPA has finalized federal requirements for natural gas-driven pneumatic pumps under subpart OOOOa. Under subpart OOOOa, each natural gas-driven diaphragm pump located at a natural gas processing plant must have zero natural gas emissions, and each natural gas-driven diaphragm pump located at a well site must capture and route emissions to a control device or process if there is an existing control device or process available onsite. Subpart OOOOa requires that VOC and methane emissions be reduced by 95 percent or greater unless the existing control device or process is not capable of reducing emissions by 95 percent or greater, unless (1) there is no control device onsite, (2) it is technically infeasible, or (3) the control device cannot achieve 95 percent control. Subpart OOOOa also includes an exemption from control requirements where a diaphragm pump operates for any period of time each calendar day for less than a total of 90 days per calendar year.

7.3.2.2 *State and Local Regulations that Specifically Require Control of VOC Emissions*

States may have permitting restrictions on VOC emissions that may apply to an emission source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met and, often, how the source may be operated. To ensure that

sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

At least one state (Wyoming) requires emissions associated with the discharge streams from all natural gas-operated pneumatic pumps be controlled by at least 98 percent or routed into a closed-loop system (e.g., sales line, collection line, fuel supply line). Several states also have registration rules for controlling fugitive VOC emissions (which may include fugitive emissions from pneumatic pumps).

7.4 Recommended RACT Level of Control

We evaluated available data obtained in the development of the 2016 NSPS final rule, comments received on the draft CTG and 2015 NSPS proposed rule, and peer review comments received on the EPA's white paper "Oil and Natural Gas Sector Pneumatic Devices." Based on our evaluation of these data and information, we recommend that VOC emissions from pneumatic pumps be controlled.

Our recommended RACT for an existing individual natural gas-driven diaphragm pump located at the well site is to capture and route VOC emissions to a control device or process where there is an existing control device or process available onsite. Our rationale for this recommendation is that, although the production segment includes both well sites and gathering and boosting stations, we currently only have reliable information for pumps located at well sites. We have determined that the cost of control for routing VOC emissions to an existing onsite control device or process would be reasonable. As presented in Tables 7-4 and 7-6 in sections 7.3.1.4 and 7.3.1.5 of this chapter, the VOC cost of control when an existing combustion device or VRU is available onsite was estimated to be \$847 per ton of VOC reduced for diaphragm pumps, without gas savings, and \$27 per ton of VOC reduced for diaphragm pumps if a VRU is used and gas savings are considered. We do not consider requiring control where there is not an existing control device or process onsite to be reasonably available technology, and the cost per ton of VOC reduced was estimated at greater than \$20,000 for diaphragm pumps. While we are not recommending that the owner or operator be required to install a control device to control pneumatic pump emissions if one is not already available, we note that control devices will likely be installed onsite for other purposes under RACT or other regulations and will be available to control emissions from pneumatic pumps to a 95 percent control level.

For purposes of our recommended RACT, a natural gas-driven diaphragm pump is a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump for purposes of our recommended RACT. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

We do not recommend RACT apply to an existing individual natural gas-driven piston pump because currently available information (including information received on the draft CTG and 2015 NSPS proposal) indicates that piston pumps are low emitting because of their small size, design and usage patterns. We determined piston pumps have emission rates between 2.2 to 2.5 scf/hr based on a joint report from the EPA and the Gas Research Institute on methane emissions from the natural gas industry. This approach is consistent with the manner in which we addressed low-bleed pneumatic controllers. After considering the low emission rates of low-bleed pneumatic controllers, we do not recommend RACT apply to these sources. Similarly, based upon the information that we have on the low emission rates of piston pumps, we are not recommending RACT apply to these sources because VOC emissions are low and would not be reasonable to control in the same manner that we recommend for diaphragm pumps. As presented in Tables 7-4 and 7-6 in sections 7.3.1.4 and 7.3.1.5 of this chapter, the VOC cost of control when an existing combustion device or VRU is available onsite was estimated to be \$7,709 per ton of VOC reduced for piston pumps, without gas savings, and \$6,876 per ton of VOC reduced for piston pumps if a VRU is used and gas savings are considered. Requiring control where there is not an existing control device or process onsite was estimated to cost more than \$200,000 per ton of VOC reduced for piston pumps.

For existing natural gas-driven diaphragm pumps at well sites, we recommend that air agencies require VOC emissions be controlled by 95 percent. Our rationale for recommending this level of emission reduction is supported by the control level achievable on a continuing basis by control devices and processes already located onsite or later installed onsite to control other emissions under RACT or other regulations. We expect that newly-installed control devices will achieve emission reductions because owners or operators are installing them to meet control requirements for other sources. In the unlikely circumstance where a control device that can achieve a 95 percent reduction is not available onsite, we recommend that owners and operators

still be required to control VOC emissions to the level achievable by the control device. We recommend that owners and operators in those instances be required to maintain documentation of the percent control the onsite control device is designed to achieve. We make this additional recommendation because it will achieve emission reductions with regard to pneumatic pumps even in the unlikely circumstance that the only available control device cannot achieve a 95 percent reduction.

We also recommend that air agencies allow for an exemption based on technical infeasibility. We recommend a technical infeasibility exemption be allowed based on information we received from industry that indicates that there may be circumstances where there is insufficient gas pressure or control device capacity, making it technically infeasible to capture and route pneumatic pump emissions to a control device or process.

We recommend that, at well sites, if a diaphragm pump operates for any period of time each calendar day for less than a total of 90 days per calendar year, the pump not be subject to the recommended control requirements. We make this recommendation to account for those intermittently used pumps/portable pumps where VOC emissions would be lower than assumed in our analysis (i.e., our analysis assumes that diaphragm pumps are operated 40 percent of the time evenly throughout the year) and not reasonable to control.

Our recommended RACT for existing diaphragm pumps located at natural gas processing plants is that they have zero VOC emissions (or 100 percent control) (unless there are functional needs including, but not limited to, response time, safety and positive actuation, requiring an emission rate greater than zero). Our rationale for selecting a VOC emission rate of zero (with functional and safety exceptions) for our recommended RACT is based on the ability of most natural gas processing plants to install and utilize an instrument air system. As discussed in section 7.3.1.3 of this chapter, by using an instrument air system, compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic system. Therefore, the use of instrument air eliminates VOC emissions from each gas-driven diaphragm pump and supports a VOC emission rate of zero.

In summary, we recommend the following RACT for pneumatic pumps in the oil and natural gas industry:

- (1) Each Diaphragm Pump Located at a Natural Gas Processing Plant: Require zero VOC emissions (or 100 percent control). This can be achieved by use of an instrument air system in place of natural gas-driven pump.
- (2) Each Diaphragm Pump Located at a Well Site: Require that VOC emissions be captured and routed to an existing control device or process that is located onsite, unless it is technically infeasible to route emissions to the existing control device or process. Require 95 percent control of VOC emissions, unless the existing control device or process cannot achieve 95 percent control. If the existing control device cannot achieve a 95 percent control, still require the emissions to be routed to the existing onsite control device to control emissions to the extent achievable and maintain documentation of the percent control the onsite control device is designed to achieve. If there is no existing control device at the location of the pump, submit a certification that there is no device. If a control device is subsequently added to the site where the pump is located, then the VOC emissions from the pump must be captured and routed to the newly installed control device.

Although sources have a choice on how they meet the RACT level of control, the technologies that will likely be used to meet the RACT level of control for each natural gas-driven diaphragm pump at a well site are either capturing and routing the VOC emissions to an onsite existing combustion device (or a subsequently installed combustion device) or capturing and routing the VOC emissions to a process using an onsite existing VRU (or a subsequently installed VRU).

Similarly, the technology that will likely be used to meet the RACT level of control for each diaphragm pump located at a natural gas processing plant is the use of an existing instrument air system assumed to already exist onsite at natural gas processing plants.

7.5 Factors to Consider in Developing Pneumatic Pump Compliance Procedures

7.5.1 Oil and Natural Gas Production Segment Recommendations

We recommend that air agencies require owners and operators of diaphragm pumps located at well sites that meet RACT by capturing emissions and routing to a control device be connected through a closed vent system and that the closed vent system be designed with no

detectable emissions (using a 500 ppm detection level, as measured using Method 21 of appendix A-7 of part 60, and ongoing monthly, olfactory and auditory inspections). We recommend that you require that owners and operators conduct an assessment and certify that the closed vent system is of sufficient design and capacity to ensure that emissions are routed to the control device. We recommend air agencies require that any detected defects be repaired as soon as practicable.

With the exception of low leg drains, high point bleeds, analyzer vent, open-ended valves and safety devices, if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process, air agencies should require that owners or operators either:

- (1) Install, calibrate, maintain and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings and either sounds an alarm or initiates notification via remote alarm to the nearest field office when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere; or
- (2) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

Secondly, we recommend that air agencies require owners and operators of diaphragm pumps at well sites provide certifications for when (1) there is no existing control device or process onsite, or (2) capturing and routing to an existing control device or process is not technically feasible.

Lastly, we recommend that air agencies require owners and operators of diaphragm pumps at well sites maintain records documenting where (1) intermittently-used/portable diaphragm pumps operate for any period of time each calendar day for less than a total of 90 calendar days per year, (2) an onsite control device or process is designed to achieve less than 95 percent reduction, and (3) a diaphragm pump is routed to a control device or a process and the control device or process is subsequently removed.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

7.5.2 Natural Gas Processing Segment Recommendations

We recommend that air agencies require owners and operators of diaphragm pumps located at natural gas processing plants maintain records documenting (1) the location and manufacturer's specifications of each pneumatic pump, (2) that the natural gas bleed rate is zero, and (3) deviations in cases where a pneumatic pump was not operated in compliance with RACT. We also recommend that air agencies require owners and operators submit annual reports that include records of deviations that occurred during the reporting period.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

8.0 EQUIPMENT LEAKS FROM NATURAL GAS PROCESSING PLANTS

This chapter presents the causes for equipment leaks from natural gas processing plants, and provides emission estimates for “model” facilities in the processing segment of the oil and natural gas industry. Methods that are designed to reduce equipment leak emissions are presented, along with our recommended RACT, and the associated VOC emission reductions and cost impacts for equipment leaks from natural gas processing plants.

This CTG and the recommended RACT included in this CTG replaces the following: *Guideline Series. Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants*. December 1983. EPA-450/3-83-007.

8.1 Applicability

For purposes of this CTG, the emissions and emission controls discussed herein would apply to the group of all equipment (except compressors and sampling connection systems) within a process unit located at a natural gas processing plant in VOC service or in wet gas service, and any device or system that is used to control VOC emissions (e.g., a closed vent system). For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, the piece of equipment must contain or contact the field gas before the extraction step at a natural gas processing plant. Equipment is defined as each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service.

8.2 Process Description and Emission Sources

8.2.1 Process Description

Natural gas processing involves the removal of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. The types of process equipment used to separate the liquids are separators, glycol dehydrators, and amine treaters. In

addition, centrifugal and/or reciprocating compressors are used to pressurize and move the natural gas from the processing facility to the transmission stations.

There are several potential sources of equipment leak emissions at natural gas processing plants. Equipment such as pumps, pressure relief devices, valves, flanges, and other connectors are potential sources that can leak due to seal failure. Other sources, such as open-ended lines and valves may leak for reasons other than faulty seals, such as an improperly installed cap on an open-ended line. In addition, corrosion of welded connections, flanges, and valves may also be a cause of equipment leak emissions. The following subsections describe potential equipment leak sources and the magnitude of the VOC emissions from natural gas processing plants.

Due to the large number of valves, pumps, and other equipment within natural gas processing plants, VOC emissions from leaking equipment can be significant (chapter 2.2 of the 1983 CTG¹²⁶ presents a description of these equipment components and is not repeated here).

8.2.2 Equipment Leak Emission Data and Emission Factors

8.2.2.1 Summary of Major Studies and Emission Factors

The 2012 NSPS TSD evaluated emissions data from equipment leaks collected from chemical manufacturing and petroleum production to assist in the development of control strategies for reducing VOC emissions from these sources.^{127,128,129} Table 8-1 presents a list of the studies consulted along with an indication of the type of information contained in the study. In addition to these sources, we evaluated the peer reviewer and public comments received on the EPA's white paper, "Oil and Natural Gas Sector Leaks."¹³⁰

¹²⁶ U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, NC, 27711. *Guideline Series. Control of Volatile Organic Compound Equipment Leaks from Natural Gas/Gasoline Processing Plants*. December 1983. EPA-450/3-83-007.

¹²⁷ Memorandum from David Randall, RTI and Karen Schaffner, RTI to Randy McDonald, U.S. Environmental Protection Agency. *Control Options and Impacts for Equipment Leaks: Chemical Manufacturing Area Source Standards*. September 2, 2008.

¹²⁸ Memorandum from Kristen Parrish, RTI and David Randall, RTI to Karen Rackley, U.S. Environmental Protection Agency. *Final Impacts for Regulatory Options for Equipment Leaks of VOC on SOCM*. October 30, 2007.

¹²⁹ Memorandum from Kristen Parrish, RTI, David Randall, RTI, and Jeff Coburn, RTI to Karen Rackley, U.S. Environmental Protection Agency. *Final Impacts for Regulatory Options for Equipment Leaks of VOC in Petroleum Refineries*. October 30, 2007.

¹³⁰ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Leaks. Report for Oil and Natural Gas Sector Leaks Review Panel*. Office of Air Quality Planning and Standards (OAQPS). April 2014.

Table 8-1. Major Studies Reviewed for Consideration of Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options^r
Protocol for Equipment Leak Emission Estimates ^a	EPA	1995	None	X	X
Methane Emissions from the Natural Gas Industry: Equipment Leaks ^b	EPA/GRI	1996	Nationwide	X	X
Greenhouse Gas Reporting Program ^c	EPA	2014	Nationwide	X	X
Inventory of Greenhouse Gas Emissions and Sinks ^d	EPA	Annual	Nationwide	X	
Methane Emissions from the Natural Gas Industry ^{e,f,g,h}	EPA/GRI	1996	Nationwide	X	X
Methane Emissions from the U.S. Petroleum Industry ⁱ	EPA	1996	Nationwide	X	
Methane Emissions from the U.S. Petroleum Industry ^j	EPA	1999	Nationwide	X	
Oil and Gas Emission Inventories for Western States ^k	Western Regional Air Partnership	2005	Regional	X	X
Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories ^l	Central States Regional Air Partnership	2008	Regional	X	X
Oil and Gas Producing Industry in Your State ^m	Independent Petroleum Association of America	2009	Nationwide		
Emissions from Natural Gas Production in the Barnett Shale and Opportunities for Cost-effective Improvements ⁿ	Environmental Defense Fund	2009	Regional	X	X
Emissions from oil and Natural Gas Production Facilities ^o	Texas Commission for Environmental Quality	2007	Regional	X	X
Petroleum and Natural Gas Statistical Data ^p	U.S. Energy Information Administration	2007-2009	Nationwide		

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options ^r
Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations ^q	EPA	1999		X	X

^a U.S. Environmental Protection Agency, *Protocol for Equipment Leak Emission Estimates*. Office of Air Quality Planning and Standards. Research Triangle Park, NC. November 1995. EPA-453/R-95-017. Available at <http://www.epa.gov/ttn/chief/efdocs/equiplks.pdf>.

^b Gas Research Institute (GRI)/U.S. Environmental Protection Agency. *Research and Development, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*. June 1996 (EPA-600/R-96-080h).

^c U.S. Environmental Protection Agency. Greenhouse Gas Reporting Program. (Annual Reporting; Current Data Available for 2011-2013). 2014.

^d U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. <https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html>.

^e U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 2: Technical Report*. EPA-600/R-96-080b. June 1996.

^f U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 3: General Methodology*. EPA-600/R-96-080c. June 1996.

^g U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 5: Activity Factors*. EPA-600/R-96-080e. June 1996.

^h U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Vol. 6: Vented and Combustion Source Summary Emissions*. EPA-600/R-96-080f. June 1996.

ⁱ U.S. Environmental Protection Agency/GRI. *Methane Emissions from the U.S. Petroleum Industry, Draft Report*. June 14, 1996.

^j ICF Consulting. *Estimates of Methane Emissions from the U.S. Oil Industry*. Prepared for the U.S. Environmental Protection Agency. 1999.

^k ENVIRON International Corporation. *Oil and Gas Emission Inventories for the Western States*. Prepared for Western Governors' Association. December 27, 2005.

^l ENVIRON International Corporation. *Recommendations for Improvements to the Central States Regional Air Partnership's Oil and Gas Emission Inventories Prepared for Central States Regional Air Partnership*. November 2008.

^m Independent Petroleum Association of America. *Oil and Gas Producing Industry in Your State*.

ⁿ Armendariz, Al. *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements*. Prepared for Environmental Defense Fund. January 2009.

^o Eastern Research Group, Inc. *Emissions from Oil and Gas Production Facilities*. Prepared for the Texas Commission on Environmental Quality. August 31, 2007.

^p U.S. Energy Information Administration. *Annual U.S. Natural Gas Wellhead Price*. U.S. Energy Information Administration. Natural Gas Navigator. Retrieved online on 12 Dec 2010 at <http://www.eia.doe.gov/dnav/ng/hist/n9190us3a.htm>.

^q Eastern Research Group, Inc. *Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operation*. Prepared for the U.S. Environmental Protection Agency. September 1999.

^r An "X" in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

8.2.2.2 *Natural Gas Processing Model Plant*

Natural gas processing plants can consist of a variety of combinations of process equipment and components. In order to conduct analyses to be used in evaluating potential options to reduce emissions from leaking equipment, the 2011 NSPS TSD and the 2012 NSPS TSD used a model plant approach.

Information related to equipment counts were obtained from a natural gas industry report.¹³¹ This document provided average equipment counts for gas production and gas processing segments. These average counts were used to develop a model plant. These equipment counts are consistent with those contained in the EPA's analysis to estimate methane emissions conducted in support of the GHGRP. The natural gas processing model plant is discussed in the following section. A summary of the model plant production equipment counts for a gas processing facility is provided in Table 8-2.

Table 8-2. Equipment Counts for Natural Gas Processing Model Plant

Equipment	Equipment Count (non-compressor equipment)
Valves	1,392
Connectors	4,392
Open-Ended Lines (OEL)	134
Pressure Relief Valve (PRV)	29

Data Source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-13, June 1996. (EPA-600/R-96-080h)

8.2.2.3 *Natural Gas Processing Model Plant Emissions*

Overview of Approach

The EPA gathered equipment leak data and cost information for the development of the proposed National Uniform Emission Standards for Equipment Leaks rule (58 FR 17898, March 26, 2012). These Uniform Standards data were used to estimate baseline emissions for a natural

¹³¹ U.S. Environmental Protection Agency/GRI. *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*. Table 4-13, June 1996. (EPA-600/R-96-080h).

gas processing model plant for the 2012 NSPS STSD and provide the baseline and controlled emission options for processing plants presented in this CTG.^{132,133}

The baseline emissions were defined as being equivalent to a 40 CFR part 60, subpart VV (subpart VV) leak detection and repair (LDAR) program, which represents the same set of requirements that apply to natural gas processing plants under 40 CFR part 60, subpart KKK (subpart KKK). The 2012 NSPS requires the implementation of 40 CFR part 60, subpart VVa (subpart VVa) and currently applies to natural gas processing plants constructed or modified after August 23, 2011. It is assumed that natural gas processing plants constructed, reconstructed or modified on or before August 23, 2011 currently still comply with subpart KKK, which is similar to the control level of subpart VV. We evaluated requiring a similar subpart VVa level of control to these plants as was required under the 2012 NSPS. We used leak frequency data (refers to the estimated percentage of equipment that will be found leaking at a given leak definition) to calculate emission estimates, in addition to several other sources of information (including the Protocol for Equipment Leak Emissions Estimates and industry data).¹³⁴ Table 8-3 provides a summary of the equipment leak frequency data used for the natural gas processing model plant. Emission factors are the estimated leak rates for an equipment type at a given leak definition and are normally given in kg/hr/piece of equipment. Table 8-4 provides a summary of the VOC equipment leak emission factors representing the subpart VVa level of control that was used for the natural gas processing model plant.

¹³² Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA/OAQPS. *Analysis of Emission Reduction Techniques for Equipment Leaks*. December 21, 2011.

¹³³ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

¹³⁴ U.S. Environmental Protection Agency. *Protocol for Equipment Leak Emission Estimates*. November 1995. EPA-453/R-95-017.

Table 8-3. Summary of Equipment Leak Frequency for Natural Gas

LDAR Program ^a	Valves	Connectors
Baseline	1.18/1.18	NA
Valves	5.95/1.91	NA
Connectors	NA	1.70/0.81

NA = Not Applicable; no equipment leak frequency percent data were available.

Data Source: Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA/OAQPS, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011, Table 5.

^a The leak frequencies provided in the tables are presented as initial leak frequency and subsequent leak frequency under the subpart VVa level of control.

Table 8-4. Summary of VOC Equipment Leak Emission Factors for the Natural Gas Processing Model Plant

Component	Uncontrolled (kg/comp-hr)	Baseline (kg/comp-hr) ^a	Subpart VVa Control Level (kg/comp-hr) ^b
Valves	3.71E-04	2.24E-04	8.85E-05
Connectors	1.04E-04	1.04E-04	3.95E-05
OEL	2.30E-03	7.34E-05	NA
PRV	1.60E-01	9.80E-02	NA

NA = Not Applicable

Data Source: Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA/OAQPS, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011, Table 7.

^a The baseline option is assumed to be equivalent to a subpart VV LDAR program.

^b Assumed to be equivalent to a subpart VVa LDAR program.

8.3 Available Controls and Regulatory Approaches

8.3.1 Available VOC Emission Control Options

The EPA has determined that leaking equipment, such as valves, pumps, and connectors are a significant source of VOC emissions from natural gas processing plants. The following subsections describe the techniques used to reduce emissions from these sources.

8.3.1.1 Leak Detection and Repair Program

The most commonly employed control technique for equipment leaks is the implementation of an LDAR program. Emission reductions from implementing an LDAR program can potentially reduce product losses, increase safety for workers and operators,

decrease exposure of hazardous chemicals to the surrounding community, and reduce emissions fees. An effective LDAR program will target leaking equipment by establishing leak definitions and require work practices to mitigate the leaks, such as monitoring frequencies for specific types of equipment (i.e., valves, pumps, and connectors). Other elements of an effective LDAR program include:

- (1) Identifying Equipment,
- (2) Monitoring Equipment,
- (3) Repairing Equipment,
- (4) Recordkeeping, and
- (5) Reporting.

The primary sources of equipment leak emissions from natural gas processing plants are valves and connectors because these are the most prevalent equipment and can number in the thousands (see Table 8-2). The major cause of emissions from valves and connectors is a seal or gasket failure due to normal wear or improper maintenance. A leak is detected whenever the measured concentration exceeds the threshold standard (i.e., leak definition) for the applicable regulation. Leak definitions vary by regulation, equipment type, and service (e.g., light liquid, heavy liquid, gas/vapor). Most NSPS regulations that were promulgated prior to 2007 have a valve leak definition of 10,000 ppm, while many National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations use a 500 ppm leak definition for valves or 1,000-ppm leak definition for other equipment such as pumps. In addition, some regulations define a leak based on visual inspections and observations (such as fluids dripping, spraying, misting, or clouding from or around equipment), sound (such as hissing), and smell.

For many NSPS and NESHAP regulations with leak detection provisions, the primary method for monitoring to detect leaking equipment is EPA Reference Method 21 (40 CFR part 60, appendix A-7). Method 21 is a procedure used to detect VOC leaks from equipment using a toxic vapor analyzer (TVA) or organic vapor analyzer (OVA).

A second method for monitoring to detect leaking components is optical gas imaging (OGI) using an infrared (IR) camera. The IR camera may be passive or active. The operator uses the passive IR cameras to scan an area to produce images of equipment leaks from a number of sources. Active IR cameras point or aim an IR beam at a potential source to indicate the presence of gaseous emissions (equipment leaks). An equipment leak is any emissions that are visualized

by an OGI instrument. The optical imaging camera can be very efficient in monitoring multiple pieces of equipment in a short amount of time. However, the optical imaging camera cannot quantify the amount or concentration of the equipment leak.

Acoustic leak detectors measure the decibel readings of high frequency vibrations from the noise of leaking fluids from equipment leaks using a stethoscope-type device. The decibel reading, along with the type of fluid, density, system pressure, and component type can be correlated into leak rate by using algorithms developed by the instrument manufacturer. The acoustic detector does not decrease the monitoring time because components are monitored separately, like the OVA or TVA monitoring. The accuracy of the measurements using the acoustic detector can also be questioned due to the number of variables used to determine the equipment leak emissions.

In addition, other monitoring tools, such as soap solution and electronic screening devices, can be used to find equipment leaks from certain types of equipment. Other factors that can improve the efficiency of an LDAR program include training programs for equipment monitoring personnel and tracking systems that address the cost efficiency of alternative equipment (e.g., competing brands of valves in a specific application).

Subpart VVa LDAR Program

One LDAR option to control VOC emissions from natural gas processing plant equipment leaks is the implementation of the subpart VVa LDAR program. This program is similar to the subpart VV monitoring program (requirements are cross-referenced in subpart KKK), but finds more leaks due to the lower leak definition, increased monitoring frequency, and the addition of connectors to the components being monitored, thereby achieving better emission reductions.

Description

The subpart VVa LDAR program requires the monitoring of pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines, valves, and connectors. These components are monitored with an OVA or TVA to determine if a component is leaking and measures the concentration of the organics if the component is leaking. Connectors and valves have a leak definition of 500 ppm. Valves are monitored monthly, connectors are monitored annually, and open-ended lines and pressure relief valves must be monitored within five days after a pressure release event to ensure they are operating without any detectable

emissions (e.g. at a concentration less than 500 ppm above background). Compressors are not included in this leak detection and repair option and are regulated separately.

Control Effectiveness

The control effectiveness of an LDAR program is based on the frequency of monitoring, leak definition, frequency of leaks, percentage of leaks that are repaired, and the percentage of reoccurring leaks. The control effectiveness of a leak program can vary from 45 to 96 percent and is dependent on the frequency of monitoring and the leak definition.¹³⁵ Descriptions of the frequency of monitoring and leak definition are described further below.

Monitoring Frequency. The monitoring frequency is the number of times each piece of equipment is checked for leaks over a given period of time. With more frequent monitoring, leaks are found and repaired sooner, thus providing higher control effectiveness.

Leak Definition. The leak definition describes the local VOC concentration at the surface of an equipment source where indications of VOC emissions are present. The leak definition is an instrument meter reading, in parts per million based on a reference compound. Decreasing the leak definition generally increases the number of leaks found during a monitoring period, which generally increases the number of leaks that are repaired.

The 2012 NSPS STSD calculated incremental emission reductions from the baseline requirements (assuming that an LDAR program equivalent to the subpart VV/subpart KKK LDAR program is currently implemented at natural gas processing plants), and the leak frequency and emission factors from a supporting document for the Equipment Leak Uniform Standards were used to calculate the emission reductions and costs. The natural gas processing plant component counts (see Table 8-2) were obtained from an EPA/GRI document.¹³⁶ The incremental VOC emission reductions for implementing a subpart VVa leak detection and repair program (as determined in the 2012 NSPS STSD) for the natural gas processing model plant was calculated to be 13 percent.

¹³⁵ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution - Background Supplemental Technical Support Document for the Final New Source Performance Standards*. April 2012. EPA Docket Number EPA-HQ-OAR-2010-0505-4550.

¹³⁶ GRI/EPA Research and Development. *Methane Emissions from the Natural Gas Industry; Volume 8: Equipment Leaks*. June 1996. EPA-600/R-96-080h.

Cost Impacts

Table 8-5 presents a summary of the incremental capital and annual costs and the cost of control (estimated in the 2012 NSPS STSD) from baseline (subpart VV) to implementing subpart VVa for the gas processing model plant. The costs obtained from the 2012 NSPS TSD have been converted to 2012 dollars from 2008 dollars using the Federal Reserve Economic Data GDP Price Deflator (Change in GDP: Implicit Price Deflator from 2008 to 2012 (5.69 percent)).¹³⁷

Table 8-5. Summary of the Gas Processing Model Plant VOC Cost of Control for the Subpart VVa Option

Annual VOC Emission Reductions (tpy)	Capital Cost (\$2012)	Annual Cost (\$2012/year)	VOC Cost of Control (\$2012/ton)	
			Without savings	With savings ^a
4.56	\$8,499	\$12,959	\$2,844	\$2,010

^a With savings calculated assuming the natural gas (82.9 percent methane) from the methane reduction has a value of \$4/Mscf. The VOC/methane ratio was assumed to be 0.278.

Table 8-6 provides a summary of the capital and annual costs and the cost of control on a component basis for the natural gas processing model plant.

Table 8-6. Summary of the Gas Processing Component VOC Cost of Control for the Subpart VVa Option

Component	Annual VOC Emission Reductions (tpy)	Capital Cost (\$2012)	Annual Cost (\$2012/year)	VOC Cost of Control (\$2012/ton)	
				Without Savings	With Savings ^a
Valves	1.82	\$5,231	\$9,280	\$5,095	\$4,261
Connectors	2.74	\$8,374	\$4,405	\$1,610	\$776

^a With savings calculated assuming the natural gas (82.9 percent methane) from the methane reduction has a value of \$4/Mscf. The VOC/methane ratio was assumed to be 0.278.

8.3.1.2 Leak Detection and Repair Program with Optical Gas Imaging

Another option to control VOC emissions is the implementation of a program that uses OGI to detect equipment leaks. The alternative work practice for equipment leaks in §60.18(g) of

¹³⁷ U.S. Bureau of Economic Analysis, Gross Domestic Product: Implicit Price Deflator (GDPDEF), retrieved from FRED, Federal Reserve Bank of St. Louis <https://research.stlouisfed.org/fred2/series/GDPDEF>. March, 26, 2015.

40 CFR part 60, subpart A allows the use of an OGI instrument to monitor equipment for leaks. This option is currently available for monitoring equipment leaks from valves, pumps, connectors and other equipment that is subject to monitoring in subpart VVa.

The alternative work practice requires periodic monitoring, based on the detection sensitivity level (grams per hour), of the affected equipment using OGI and an annual monitoring survey of the affected equipment using a Method 21. Method 21 monitoring allows the facility to determine the concentration of a leak and to then use emission factors found in the EPA's emissions leak protocol to quantify emissions from equipment leaks, because the OGI system can only provide the presence of the equipment leaks.

Modeling results, conducted in support of the alternative work practice standard, showed a work practice repeated bimonthly with a detection limit of 60 g/hr range was equivalent to existing Method 21 work practices. The model generated different detection limits for the 500 and 10,000 ppm thresholds in existing rules. Based on modeling, the alternative work practice standard reflects the mass detection limit for 500 ppm, thus, providing equivalency for both 500 and 10,000 ppm thresholds.¹³⁸ The alternative work practice option is assumed to have the same control effectiveness as the subpart VVa monitoring program.

8.3.2 Existing Federal, State and Local Regulations

8.3.2.1 *Federal Regulations that Specifically Require Control of VOC Emissions*

Federal regulations that regulate VOC emissions from equipment leaks at natural gas processing plants include 40 CFR part 60 subpart OOOOa, subpart OOOO, and subpart KKK; and the 1983 CTG document (established a recommended RACT for VOC for natural gas processing plants at a level of control equivalent to subpart KKK).

8.3.2.2 *State and Local Regulations that Specifically Require Control of VOC Emissions*

States may have permitting restrictions on VOC emissions that may apply to an emissions source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed,

¹³⁸ 73 FR 78199, December 22, 2008.

what emission limits must be met, and often how the source must be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements.

We assume that all states currently regulate equipment leaks at existing natural gas processing plants at the 1983 CTG document and subpart VV level of control.

8.4 Recommended RACT Level of Control for Equipment Leaks from Equipment at Natural Gas Processing Plants

As discussed in section 8.3.2 of this chapter, existing federal, state and local regulations already require the reduction of VOC emissions using an LDAR program. The 2012 NSPS requires a 40 CFR part 60 subpart VVa LDAR monitoring program for processing plants. The 2012 NSPS reported a cost of control for natural gas processing plants to be \$2,844 per ton of VOC removed for the 40 CFR part 60 subpart VVa option.

Based on costs and existing LDAR programs that are already employed at natural gas processing plants, we recommend that RACT for natural gas processing plants be the implementation of an LDAR program equivalent to what is required under 40 CFR part 60 subpart VVa for equipment (with the exception of compressors and sampling connection systems) in VOC service. This RACT recommendation would increase the stringency from the currently implemented LDAR programs at most existing natural gas processing plants (that were built prior to 2012) in VOC service by lowering the leak definitions, increasing the monitoring frequency, and including additional equipment. The subpart VVa leak detection and repair program requires the annual monitoring of connectors using an OVA or TVA (500 ppm leak definition), monthly monitoring of valves (500 ppm leak definition) and requires open-ended lines and pressure relief devices to operate with no detectable emissions (less than 500 ppm above background). The estimated annual incremental VOC emission reductions for the recommended RACT for a natural gas processing plant was estimated to be 4.56 tpy (see Table 8-5 of this chapter). The annual VOC emission reductions assume a baseline level of control equivalent to the 40 CFR part 60, subpart VV LDAR program. Table 8-5 presents the gas processing model plant VOC cost of control for the recommended RACT. The costs assume a baseline level of control equivalent to the 40 CFR part 60, subpart VV LDAR program. The

recommended RACT VOC cost of control is estimated to be \$2,844 per ton of VOC reduced without savings and \$2,010 with savings.

In summary, we recommend the following RACT for equipment leaks at natural gas processing plants:

RACT for Equipment Leaks at Natural Gas Processing Plants: We recommend the implementation of an LDAR program equivalent to what is required under 40 CFR part 60 subpart VVa for equipment (with the exception of compressors and sampling connection systems) in VOC service.

8.5 Factors to Consider in Developing Equipment Leak Compliance Procedures

Existing natural gas processing plants that would be subject to the recommended RACT are already subject to an LDAR program and the basic elements of the LDAR program for the facility are in place. However, the LDAR program would need to be modified to increase the stringency from the currently implemented LDAR program by requiring annual monitoring of connectors using an OVA or TVA (500 ppm leak definition), and lowering the leak definition for valves (500 ppm). As with the currently implemented LDAR program, to ensure that equipment in VOC service that leak at natural gas processing plants are properly monitored and repaired under the LDAR RACT recommendations, we suggest that air agencies specify monitoring frequency, equipment repair, and recordkeeping and reporting requirements to document compliance.

Monitoring frequencies vary according to the applicable regulation, but are typically weekly, monthly, quarterly and yearly. The monitoring frequency depends on the equipment type and periodic leak rate for the equipment. For each piece of equipment that is found to be leaking, the first attempt at repair should be made within a reasonable period of time, such as no later than five calendar days after each leak is detected. First attempts at repair include, but are not limited to, the following best practices, where practicable and appropriate:

- (1) Tightening of bonnet bolts,
- (2) Replacement of bonnet bolts,
- (3) Tightening of packing gland nuts, and
- (4) Injection of lubricant into lubricated packing.

Once the equipment is repaired, it should be re-monitored over the next several days to ensure the leak has been successfully repaired. Another method that can be used to repair equipment is to replace the leaking equipment with a “leakless” equipment or other technologies.

When implementing an LDAR program, we recommend that air agencies consider including recordkeeping requirements that require owner/operators of subject facilities to maintain a list of identification numbers for all equipment subject to an equipment leak regulation. A list of equipment that is designated as “unsafe to monitor” should also be maintained with an explanation/review of conditions for the designation. Detailed schematics, equipment design specifications (including dates and descriptions of any changes), and piping and instrumentation diagrams should also be maintained with the results of performance testing and leak detection monitoring.

The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

9.0 FUGITIVE EMISSIONS FROM WELL SITES AND GATHERING AND BOOSTING STATIONS

Fugitive emissions from components in the oil and natural gas industry are a source of VOC emissions. This chapter discusses the sources of fugitive emissions, and provides VOC emission estimates for well sites and gathering and boosting stations in the production segment (located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or point of custody transfer to an oil pipeline). This chapter also presents a description of programs that are designed to reduce fugitive emissions, along with costs, and emission reductions. Finally, this chapter provides a discussion of our recommended RACT and the estimated VOC emission reductions and costs for fugitive emissions from well sites and gathering and boosting stations in the production segment.

9.1 Applicability

For purposes of this CTG, the emissions and programs to control emissions discussed herein would apply to the collection of fugitive emissions components at well sites with an average production of greater than 15 barrel equivalents per well per day (15 barrel equivalents)¹³⁹ and the collection of fugitive emissions components at gathering and boosting stations in the production segment.

For the purposes of this CTG, fugitive emission reduction recommendations would not apply to well sites that only contain wellheads.

Fugitive emissions, for the purposes of applicability of this CTG, means those emissions from a stationary source that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening. Equipment leak emissions at natural gas processing plants are covered under chapter 8 of this document.

¹³⁹ Natural gas production converted to barrel equivalents uses the conversion of 0.178 barrels of crude oil to 1000 cubic feet of natural gas. Based upon conversion factor used for the no longer in service U.S. EIA Financial Reporting System for Major Energy Producers.

9.2 Fugitive Emissions Description and Data

9.2.1 Fugitive Emissions Description

There are several potential sources of fugitive emissions throughout the oil and natural gas industry. Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Changes in pressure, temperature, or mechanical stresses can also cause components or equipment to emit fugitive emissions. Poor maintenance or operating practices, such as improperly reseated PRVs or thief hatches on controlled storage vessels that are left open after sampling, are also potential sources of fugitive emissions. Potential sources of fugitive emissions include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines (OELs), pressure relief devices such as PRVs, pump seals, valves, or improperly controlled liquid storage tanks. These fugitive emissions do not include devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pneumatic pumps, insofar as the natural gas and associated VOC emissions discharged from the device's vent is not considered a fugitive emission.

For the purposes of our RACT analysis for fugitive emissions from components and equipment, we differentiated between the definition of "equipment" for purposes of controlling equipment leaks for oil and natural gas processing plants in subpart OOOO¹⁴⁰ and the definition we use for the purposes of addressing fugitive emissions from oil and natural gas well sites and gathering and boosting stations. For purposes of our RACT analysis, "fugitive emissions component(s)" are the focus of our analysis for fugitive emissions from oil and natural gas well sites and gathering and boosting stations. The definition for "fugitive emissions component" is as follows:

Fugitive emissions component means any component that has the potential to emit fugitive emissions of VOC at a well site or gathering and boosting station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not already subject to equipment and fugitive emissions monitoring, thief hatches or other openings on a controlled storage vessel, compressors, instruments and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions

¹⁴⁰ The Oil and Natural Gas Sector NSPS (40 CFR 60, subpart OOOO) specifically defines "equipment" relative to standards for equipment leaks of VOC from onshore natural gas processing plants. As used in this chapter, the term "equipment" is used in a broader context and is not meant to be limited by the manner in which the term is currently used in subpart OOOO.

components, insofar as the natural gas and associated VOC emissions discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

9.2.2. Emission Data and Emission Factors

9.2.2.1 Summary of Major Studies and Emission Factors

In April of 2014, we published a white paper¹⁴¹ which summarized our current understanding of VOC fugitive emissions at onshore oil and natural gas production, processing and transmission and storage facilities (referred to herein as the “equipment leaks white paper”). The equipment leaks white paper also outlined our understanding of the available mitigation techniques (practices and equipment) available to reduce these emissions along with the cost and emission reduction potential of these practices and technologies.

The equipment leaks white paper provided a summary of fugitive emission studies at oil and natural gas well sites and gathering and boosting stations in the production segment. Throughout the development of this CTG, the EPA evaluated a variety of emissions data and emission reduction options for fugitive emissions. Many of the studies in the equipment leaks white paper were consulted. Table 9-1 presents a list of the studies consulted along with an indication of the type of information contained in each study.

Table 9-1. Major Studies Reviewed for Emissions and Activity Data

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options ^m
Protocol for Equipment Leak Emission Estimates ^a	EPA	1995	None	X	X
Methane Emissions from the Natural Gas Industry: Equipment Leaks ^b	EPA/GRI	1996	Nationwide	X	X
Greenhouse Gas Reporting Program ^c	EPA	2013	Facility	X	
Inventory of Greenhouse Gas Emissions and Sinks ^d	EPA	Annual	Regional	X	
Measurements of Methane Emissions at Natural Gas	Multiple Affiliations,	2013	Nationwide	X	X

¹⁴¹ U.S. EPA. *Oil and Natural Gas Sector Leaks*, OAQPS. Research Triangle Park, NC. April 2014. Available at <http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf>.

Report Name	Affiliation	Year of Report	Activity Factors	Emissions Data	Control Options ^m
Production Sites in the United States ^c	Academic and Private				
City of Fort Worth Natural Gas Air Quality Study, Final Report ^f	City of Fort Worth	2011	Fort Worth, TX	X	X
Measurements of Well Pad Emissions in Greeley, CO ^g	ARCADIS/Sage Environmental Consulting/ EPA	2012	Colorado	X	X
Quantifying Cost-Effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras ^h	Carbon Limits	2013	Canada and the U.S.	X	X
Mobile Measurement Studies in Colorado, Texas, and Wyoming ⁱ	EPA	2012 and 2014	Colorado, Texas, and Wyoming	X	X
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries ^j	ICF International	2014	Nationwide	X	X
Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants ^k	Clearstone Engineering, Ltd.	2002	4 gas processing plants	X	X
Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites ^l	Clearstone Engineering, Ltd.	2006	5 gas processing plants, 12 well sites	X	X

^a U.S. Environmental Protection Agency. *Protocol for Equipment Leak Emission Estimates*. Office of Air Quality Planning and Standards. Research Triangle Park, NC. November 1995. EPA-453/R-95-017. Available at <http://www.epa.gov/ttn/chief/efdocs/equiplks.pdf>.

^b U.S. Environmental Protection Agency/GRI. Research and Development, *Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*. June 1996 (EPA-600/R-96-080h).

^c U.S. Environmental Protection Agency. Greenhouse Gas Reporting Program. (Annual Reporting; Current Data Available for 2011-2013). 2014.

^d U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks*. Washington, DC. <https://www3.epa.gov/climatechange/ghgemissions/usinventoryreport.html>.

^e Allen, David, T., et al. *Measurements of methane emissions at natural gas production sites in the United States*. Proceedings of the National Academy of Sciences (PNAS) 500 Fifth Street, NW NAS 340 Washington, DC 20001 USA. October 29, 2013. 6 pgs.

^f ERG and Sage Environmental Consulting, LP. *City of Fort Worth Natural Gas Air Quality Study, Final Report*. Prepared for the City of Fort Worth, Texas. July 13, 2011. Available at <http://fortworthtexas.gov/gaswells/default.aspx?id=87074>.

^g Modrak, Mark T., et al. *Understanding Direct Emissions Measurement Approaches for Upstream Oil and Gas Production Operations*. Air and Waste Management Association 105th Annual Conference and Exhibition, June 19-22, 2012 in San Antonio, Texas.

^h Carbon Limits. *Quantifying cost-effectiveness of systematic Leak Detection and Repair Programs using Infrared cameras*. December 24, 2013. Available at http://www.catf.us/resources/publications/files/CATF-Carbon_Limits_Leaks_Interim_Report.pdf.

ⁱ Thoma, Eben D., et al. *Assessment of Methane and VOC Emissions from Select Upstream Oil and Gas Production Operations Using Remote Measurements, Interim Report on Recent Studies*. Proceedings of the 105th Annual Conference of the Air and Waste Management Association, June 19-22, 2012 in San Antonio, Texas.

^j ICF International. *Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries*. ICF International (Prepared for the Environmental Defense Fund). March 2014.

^k Clearstone Engineering Ltd. *Identification and Evaluation of Opportunities to Reduce Methane Losses at Four Gas Processing Plants*. June, 2002.

^l Clearstone Engineering Ltd. *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites*. March 2006.

^m An “X” in this column does not necessarily indicate that the EPA has received comprehensive data on control options from any one of these reports. The type of emissions control information that the EPA has received from these reports varies substantially from report to report.

9.2.2.2 Model Plants

Facilities in the oil and natural gas industry consist of a variety of combinations of process equipment and components. This is particularly true in the production segment of the industry, where “surface sites” can vary from sites where only a wellhead and associated piping is located to sites where a substantial amount of separation, treatment, and compression occurs. In order to conduct analyses to be used in evaluating potential options to reduce fugitive emissions from well sites and gathering and boosting stations, a model plant approach was used. The following sections discuss the creation of these model plants.

Oil and Natural Gas Production Well Sites

Oil and natural gas production varies from one site to the next. Some production sites may include only a single wellhead that is extracting oil or natural gas from the ground, while other sites may include multiple wellheads attached to a well site. A well site is a site where the production, extraction, recovery, lifting, stabilization, separation, and/or treating of petroleum and/or natural gas (including condensate) occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) that have associated components that may be sources of fugitive emissions

associated with these operations. A well site can serve one well on a pad or multiple wells on a pad. Therefore, the number of components with potential for fugitive emissions can vary depending on the number of wells at the site.

Model plants were developed using the average number of wells associated with a well site using data from the Drillinginfo HPDI database.¹⁴² Baseline fugitive emissions from well sites depend upon the quantity of equipment and components, which in turn is based on this estimate of wells per pad. To estimate the average number of wells co-located on the same site as a new well completion or recompletion, the EPA developed a pair of algorithms that identified new and existing wells within a given distance of a new well completion or recompletion. This distance was assumed to represent the distance that, if other wells were within the distance, the wells would likely be co-located with the well under examination on the same site. The algorithms were written in the open source R programming language.¹⁴³

The HPDI well and production data used to estimate the average number of well co-located on a well site drew upon the latitude and longitude of new well completions and recompletions as well as the coordinates of all wells producing oil or natural gas in 2012. The first algorithm estimated the distances between each new completion and recompletion and all producing wells, which also includes wells newly completed and producing in 2012 within the same county as the completed well. If the distance between the completed well and producing well was less than the assumed size of a typical well site, we assumed the two wells were co-located. This algorithm progressed county by county across the U.S. where oil and natural gas production occurred in 2012 to identify all co-located wells in the U.S. The number of new well completions and recompletions in 2012 was about 44,000, which includes oil and natural gas wells whether they were hydraulically fractured or not. Wells producing in 2012 numbered about 1.27 million. The second algorithm processed the results of the first such that a well can only appear once on a modelled well site.

Once these algorithms were complete and produced a results file, we converted the results into a “kml” file that enabled the visual inspection of the results within Google Earth. We did not visually inspect every site in the U.S. linked to a 2012 completion or recompletion as

¹⁴² Drilling Information, Inc. 2011. *DI Desktop*. 2011 Production Information Database.

¹⁴³ See the website <<http://www.r-project.org/>> for more information on R (The R Project for Statistical Computing). R is a free software environment for statistical computing and graphics.

they numbered greater than 20,000. Instead, we examined sites randomly across a range of oil and natural gas production regions. The results of this visual examination indicated the algorithms were functioning as intended.

We estimated the number of wells per site assuming sites of one, two and three acres, based upon input from petroleum industry data analysts. Table 9-2 shows the high-level results of these analyses.

Table 9-2. Estimated Average Number of Wells per Site of New Well Completion in 2012

Assumed Well Site Size	No. of Well Sites	No. of Wells at Sites	Average of Wells Per Site
One Acre	29,213	50,599	1.73
Two Acres	28,938	52,422	1.81
Three Acres	28,710	53,981	1.88

For assumed well sites of two acres, the analysis identified 28,938 independent well sites that contained 52,422 wells (including both single and multi-well sites). The total number of wells identified as being co-located with new well completions and recompletions exceeds the total number of completions and recompletions because the sites include about 8,500 existing wells producing in 2012.

However, the high level summary presented in Table 9-3 masks variation by basins and well types. Table 9-3 presents more detail along these dimensions for the assumed two-acre well site.

Table 9-3. Estimated Average Number of Wells per Two-Acre Site of New Well Completions and Recompletions in 2012, by HPDI Basin and Type of Well (Oil or Natural Gas, Hydraulically Fractured or Not)

HPDI Basin	No. Of Sites	Oil Well Completions			Natural Gas Well Completions			Total
		HF	Not HF	All	HF	Not HF	All	
Los Angeles	23	N/A	13.07	13.07	N/A	N/A	N/A	13.07
Piceance	111	2.00	1.00	1.75	6.72	11.75	10.14	9.84
Arctic Ocean	2	N/A	5.50	5.50	N/A	N/A	N/A	5.50
Green River	164	2.23	1.57	2.01	4.37	1.13	4.19	3.88
Unidentified	226	1.18	3.57	3.38	1.00	1.77	1.44	3.22
San Joaquin Basin	1,745	1.56	3.46	3.21	2.61	1.42	2.24	3.16
Arkoma Basin	374	4.00	1.33	2.00	3.06	1.00	3.01	3.00
Denver Julesburg	826	2.63	3.10	2.75	1.48	3.14	1.72	2.46
Ft. Worth Basin	1,305	2.05	1.86	1.91	3.27	1.10	2.93	2.33
Central Western Overthrust	7	1.50	N/A	1.50	2.60	N/A	2.60	2.29
Ventura Basin	1	N/A	2.00	2.00	N/A	N/A	N/A	2.00
Arctic Slope	42	N/A	2.13	2.13	N/A	1.65	1.65	1.99
Ouachita Folded Belt	181	2.01	1.90	1.99	1.50	1.00	1.43	1.97
Salina Basin	13	N/A	1.92	1.92	N/A	N/A	N/A	1.92
Palo Duro Basin	81	1.42	1.97	1.89	1.00	N/A	1.00	1.86
Uinta	548	1.16	1.33	1.32	N/A	3.33	3.33	1.83
Texas & Louisiana Gulf Coast	3,994	2.03	1.82	1.96	1.37	1.14	1.28	1.79
Central Kansas Uplift	450	N/A	1.78	1.78	N/A	1.53	1.53	1.77
Permian Basin	8,507	1.66	1.76	1.69	1.50	1.57	1.52	1.68
Sedgwick Basin	240	N/A	1.67	1.67	1.67	1.55	1.55	1.62
Las Animas Arch	25	1.00	1.64	1.61	N/A	1.50	1.50	1.60
Nemaha Anticline	38	N/A	1.55	1.55	N/A	N/A	N/A	1.55
Arkla Basin	811	1.09	1.57	1.49	1.47	1.09	1.42	1.46
Chautauqua Platform	461	1.36	1.57	1.49	1.64	1.03	1.35	1.45
Cook Inlet Basin	9	N/A	2.00	2.00	N/A	1.29	1.29	1.44
Appalachian	2,496	1.14	1.05	1.10	2.28	1.10	1.77	1.43
Williston	1,570	1.36	1.00	1.35	1.43	1.00	1.39	1.35
Cherokee Basin	271	1.17	1.29	1.29	N/A	1.69	1.69	1.35
San Juan	158	1.00	1.00	1.00	1.38	1.20	1.37	1.31
East Texas Basin	618	1.25	1.74	1.52	1.22	1.06	1.21	1.31
Forest City Basin	172	N/A	1.28	1.28	N/A	N/A	N/A	1.28
Anadarko Basin	2,663	1.17	1.77	1.37	1.09	1.29	1.13	1.27
South Oklahoma Folded Belt	167	1.17	1.36	1.30	1.11	1.11	1.11	1.24
Chadron Arch	49	N/A	1.22	1.22	N/A	N/A	N/A	1.22

HPDI Basin	No. Of Sites	Oil Well Completions			Natural Gas Well Completions			Total
		HF	Not HF	All	HF	Not HF	All	
Sacramento Basin	13	N/A	N/A	N/A	N/A	1.15	1.15	1.15
Mississippi & Alabama Gulf Coast	132	1.00	1.18	1.14	1.00	1.00	1.00	1.14
Central Montana Uplift	10	1.13	1.00	1.10	N/A	N/A	N/A	1.10
Big Horn	30	1.10	1.11	1.11	1.00	N/A	1.00	1.10
Powder River	232	1.15	1.03	1.12	1.05	1.00	1.04	1.10
Sweet Grass Arch	17	1.00	1.08	1.05	1.50	1.00	1.33	1.10
Paradox	13	1.00	1.10	1.09	1.00	N/A	1.00	1.08
Black Warrior Basin	57	1.00	1.00	1.00	1.00	1.75	1.07	1.05
Wind River	63	1.00	1.02	1.02	1.00	1.00	1.00	1.02
Wasatch Uplift	1	N/A	1.00	1.00	N/A	N/A	N/A	1.00
North Park	2	1.00	1.00	1.00	N/A	N/A	N/A	1.00
Raton	20	N/A	N/A	N/A	1.00	1.00	1.00	1.00
Grand Total	28,938	1.64	1.99	1.79	1.90	1.76	1.86	1.81

The data presented in Table 9-3 indicates that the concentration of wells at production sites varies greatly by basin. However, the analysis also indicates that most wells sites have relatively few or no co-located wells, which brings the national average of wells per new completion or recompletion site to 1.81 for the two-acre well site. While the analysis shows variation by basin, at the national level, there is relatively little variation across oil and natural gas well completion sites and whether the new wells were completed or recompleted using hydraulic fracturing. For example, oil well sites averaged 1.79 wells per site while natural gas wells averaged 1.86.

As a result of this analysis, we decided to use the two-acre well site as the assumed maximum size of a site to estimate the number of wells co-located at sites of new completions and recompletions. Also, to simplify analysis of costs and emissions at well sites, we rounded the 1.81 national average wells per site to 2.

While we are confident that the assumed two-acre well site is a reasonable size to capture most co-located wells in 2012, it is by no means a perfect assumption. First, industry and state regulatory trends indicate that well drilling will likely become increasingly concentrated on sites, potentially leading to an increase in the average number of wells per well site. However, it is not possible at this point to forecast this increasing concentration, especially with the variations by

fields described above. Also, it is possible that two acres is too small to accurately estimate the number of co-located wells for large well sites in some fields. As a result, the algorithms might result in an underestimate of the average number of wells at a site and identify more than one site when in actuality there is only one. Alternatively, the assumed two acres might overestimate the size of sites in some fields and, as a result, pull in more than one site, overestimating the number of wells on the site. We also noted that the latitude and longitude values on many wells were likely incorrect or exact duplicates of other wells. Despite these caveats, we believe that the well site analysis described here produces a reasonable estimate of national average of number of wells on new well completion and recompletion sites in 2012. Therefore, based on this analysis, the model plants for oil and natural gas well sites are based on a well site with 2 wells.

Baseline model plant emissions for natural gas and oil production well sites were calculated using the fugitive emissions equipment counts from the GHG Inventory, derived from GHGRP, EPA/GRI and 40 CFR part 98, subpart W tables, and the component oil and natural gas production emission factors from AP-42.¹⁴⁴ Annual emissions were calculated assuming 8,760 hours of operation each year. We used equipment count data from the EPA GHG Inventory to calculate the average counts of production equipment located at a well site. The types of production equipment located at a well site include: gas wellheads, separators, meters/piping, heaters, and dehydrators. The types of components that are associated with these production equipment types include: valves, connectors, open-ended lines, and pressure relief valves. Component counts for each of the equipment items were calculated using the average component counts for gas production equipment in the Eastern U.S. and the Western U.S. Fractions of components were rounded up to the nearest integer.

For natural gas well sites, the model plant was developed using the average equipment and fugitive emissions components counts for natural gas production data from the EPA/GRI report and the 2016 GHG Inventory. The average equipment count for a natural gas well was estimated by using the average equipment counts per well in the 2016 GHG Inventory (based on GHGRP data), and by weighing the average component counts per equipment for the Eastern and Western U.S. data sets for gas production equipment. This resulted in 2 separators, 3 meters/piping, 1 in-line heater, and 1 dehydrator per well. The total natural gas well site

¹⁴⁴ U.S. Environmental Protection Agency. *Protocol for Equipment Leak Emission Estimates*. Table 2-4. November 1995. EPA-453/R-95-017.

equipment counts were calculated by multiplying the average well equipment values by the average number of wells per well site (2), and rounding the product to the nearest integer. Average component counts for each of the equipment items were calculated using the average component counts for production equipment in the Eastern U.S. and the Western U.S. from the EPA/GRI study. The total number of fugitive emissions components was calculated by multiplying the rounded equipment counts by the component count per equipment and rounding to the nearest integer. Table 9-4 presents a summary of the fugitive emissions component counts for natural gas well sites.

For oil well sites, two model plants were developed in order to account for emissions variability. One oil well model plant was developed for oil wells with a gas-to-oil ratio less than 300 standard cubic feet of gas per stock barrel of oil (GOR less than 300) and another model plant was developed for oil wells with a gas-to-oil ratio greater than or equal to 300 standard cubic feet of gas per stock of barrel oil (GOR greater than or equal to 300).

The equipment count for the oil well model plant with a GOR less than 300 consists of 2 oil wellheads, 1 separator, 1 header and 1 heater/treater. These equipment counts were obtained from 2016 GHG Inventory data. The component counts for these equipment types were obtained from Table W-1C of subpart W and are the weighted average component counts for onshore production equipment in the Eastern U.S. and Western U.S.

The equipment count for the oil well model plant with a GOR greater than or equal to 300 consists of 2 oil wellheads, 1 separator, 1 header and 1 heater/treater and 3 meters/piping. These equipment counts for separators, headers, and heater/treaters were obtained from the 2016 GHG Inventory data for petroleum systems, while the meter/piping counts were obtained from the 2016 GHG Inventory data for natural gas systems to reflect gas production at the sites.

The component counts for these equipment types were obtained from Table W-1C of subpart W for all but meters/piping, which were obtained from Table W-1B of subpart W. The component counts are the weighted average component counts for onshore production equipment in the Eastern U.S. and Western U.S. The total number of fugitive emissions components for oil well sites equipment (for both model plants) was calculated by multiplying the rounded equipment counts by the component count per piece of equipment and rounding to the nearest integer. Table 9-5 presents a summary of the fugitive emissions component counts for oil well site model plants.

Table 9-4. Average Fugitive Emissions Component Count for Natural Gas Well Site Model Plant

Equipment	Model Plant Equipment Counts	Average Component Count per Equipment ^a				Average Component Count per Model Plant			
		Valves	Connectors	OELs	PRVs	Valves	Connectors	OELs	PRVs
Gas Wellheads	2	9.5	37.0	0.7	0.0	19.0	74.0	1.4	0.0
Separators	2	21.6	68.5	3.7	1.2	43.2	137.0	7.4	2.4
Meters/Piping	3	12.9	47.8	0.5	0.5	38.7	143.4	1.5	1.5
In-Line Heaters	1	14.0	65.0	2.0	1.0	14.0	65.0	2.0	1.0
Dehydrators	1	24.0	90.0	2.0	2.0	24.0	90.0	2.0	2.0
Total						138.9	509.4	14.3	6.9
Rounded up Total						139	510	15	7.0

^a Data Source: EPA/GRI. *CH₄ Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

Table 9-5. Average Fugitive Emissions Component Count for Oil Well Site Model Plants

Production Equipment	Model Plant Production Equipment Counts	Average Component Count Per Unit of Production Equipment ^a					Average Component Count Per Model Plant				
		Valves	Flanges	Connectors	OELs	PRVs	Valves	Flanges	Connectors	OELs	PRVs
Oil Well Model Plant (< 300 GOR) ^a											
Oil Wellheads	2	5	10	4	0	1	10	20	8	0	2
Separators	1	6	12	10	0	0	6	12	10	0	0
Headers	1	5	10	4	0	0	5	10	4	0	0
Heater/Treaters	1	8	12	20	0	0	8	12	20	0	0
Total							29	54	42	0	2
Oil Well Model Plant (≥ 300 GOR) ^b											
Oil Wellheads	2	5	10	4	0	1	10	20	8	0	2
Separators	1	6	12	10	0	0	6	12	10	0	0
Headers	1	5	10	4	0	0	5	10	4	0	0
Heater/Treaters	1	8	12	20	0	0	8	12	20	0	0
Meters/Piping	3	12.9	0	47.8	0.5	0.5	39	0	144	2	2
Total							68	54	186	2	4

^a Oil well (<300 GOR) component counts obtained from 40 CFR Part 98, subpart W, Table W-1C.

^b Oil well (≥300 GOR) component counts obtained from 40 CFR Part 98, subpart W, Tables W-1B and W-1C.

The baseline emissions for the natural gas well site and oil well model plants were calculated using equipment counts for the natural gas well site model plant and the oil and natural gas production AP-42 total organic compound (TOC) emission factors. Annual emissions were calculated assuming 8,760 hours of operation each year. The TOC emissions were converted to VOC using VOC/TOC weight ratios in the 2011 Gas Composition Memorandum.¹⁴⁵ The fugitive VOC emissions for the natural gas well site model plant were determined to be 1.53 tpy of VOC. The fugitive emissions for the oil well site model plant with a GOR less than 300 was determined to be 0.33 tpy of VOC. The fugitive emissions for the oil well site model plant with a GOR greater than or equal to 300 was determined to be 0.73 tpy of VOC. The VOC emission estimates were used to evaluate the potential emission reductions and cost of control of a fugitive emission reduction program. Table 9-6 presents the emission factors for the natural gas and oil production segments. A summary of the equipment counts, average TOC emission factors and VOC emissions for natural gas well and oil well sites are provided in Tables 9-7 and 9-8, respectively.

Table 9-6. Oil and Natural Gas Production Operations Average TOC Emission Factors

Component Type	Component Service	TOC Emission Factor^a (kg/hr/source)
Valves	Gas	4.5E-03
Flanges	Gas	3.9E-04
Connectors	Gas	2.0E-04
OEL	Gas	2.0E-03
PRV	Gas	8.8E-03

^a Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)

¹⁴⁵ Memorandum to Bruce Moore from Heather Brown. *Composition of Natural Gas for Use in the Oil and Natural Gas Sector Rulemaking*. EC/R, Incorporated. July, 2011.

Table 9-7. Estimated Fugitive VOC Emissions for Natural Gas Production Model Plant

Natural Gas Well Site Model Plant Component	Model Plant Component Count^a	Uncontrolled TOC Emission Factor^b (kg/hr/comp)	Uncontrolled VOC Emissions (tpy)^c
Valves	139	0.0045	1.166
Connectors	510	0.0002	0.190
OELs	15	0.002	0.056
PRVs	7	0.0088	0.115
Total			1.53

^a Fugitive emissions component count values for model plant are based on a 2-wellhead site and are rounded to the nearest integer.

^b TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.

^c VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from the 2011 Gas Composition Memorandum.

Table 9-8. Estimated Fugitive VOC Emissions for Oil Well Site Model Plants

Oil Well Site Model Plant Component	Model Plant Component Count^a	Uncontrolled Emission Factor^b (kg/hr/comp)	Uncontrolled VOC Emissions (tpy)^c
<i>Oil Well Model Plant (< 300 GOR)</i>			
Valves	29	0.0045	0.243
Flanges	54	0.00039	0.039
Connectors	42	0.0002	0.016
OELs	0	0.002	0
PRVs	2	0.0088	0.033
Total			0.33
<i>Oil Well Model Plant (≥ 300 GOR)</i>			
Valves	68	0.0045	0.571
Flanges	54	0.00039	0.039
Connectors	186	0.0002	0.069
OELs	2	0.002	0.007
PRVs	4	0.0088	0.066
Total			0.75

^a Fugitive emissions component count values for model plant are based on a 2-wellhead pad and are rounded to the nearest integer.

^b TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.

^c VOC emissions calculated using 0.193 weight ratio for VOC/TOC obtained from the 2011 Gas Composition Memorandum.

Gathering and Boosting Stations

Gathering and boosting stations are sites that collect natural gas from well sites and direct them to the natural gas processing plants. These stations have similar equipment to well sites; however they are not directly connected to the wellheads. The EPA/GRI document does not have specific equipment counts for the gathering and boosting segment, but does include equipment counts for gathering compressors within the oil and natural gas production data. To estimate the equipment at a gathering and boosting model plant, the weighted averages of equipment counts

for the Eastern and Western U.S. data sets for onshore production equipment were calculated. The weighted averages of the data sets were determined to be 11 separators, 7 meters/piping, 5 gathering compressors, 7 in-line heaters, and 5 dehydrators. These average equipment counts were used to create the model plant for gathering and boosting stations. The components for gathering compressors were included in the model plant total counts, but the compressor seals were excluded. Compressor seals are addressed in chapter 5 of this document. Table 9-9 presents a summary of the fugitive emissions component counts for oil and gas gathering and boosting stations.

Baseline emissions were calculated using the component counts and the TOC emission factors for oil and natural gas production (See Table 9-6). Table 9-10 summarizes the baseline emissions for gathering and boosting stations. The average fugitive emissions from a gathering and boosting station were determined to be 9.8 tpy of VOC. The VOC emission estimate was used to evaluate the potential emission reductions and cost of control of a fugitive emissions reduction program.

Table 9-9. Average Component Count for the Oil and Natural Gas Production Gathering and Boosting Station Model Plant

Equipment	Model Plant Equipment Counts	Average Component Count per Equipment ^a				Average Component Count per Model Plant			
		Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves
Separators	11	22	68	4	1	242	748	44	11
Meters/Piping	7	13	48	0	0	91	336	0	0
Gathering Compressors	5	71	175	3	4	355	875	15	20
In-Line Heaters	7	14	65	2	1	98	455	14	7
Dehydrators	5	24	90	2	2	120	450	10	10
Total						906	2,864	83	48

^a Data Source: EPA/GRI. Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Tables 4-4 and 4-7, June 1996. (EPA- 600/R-96-080h).

Table 9-10. Estimated Fugitive TOC and VOC Emissions for the Oil and Natural Gas Production Gathering and Boosting Station Model Plant

Component	Model Plant Component Count ^a	Component TOC Emission Factor (kg/hr/ component) ^b	VOC Emissions (tons/yr) ^c
Valve	906	0.0045	7.6
Connectors	2,864	0.0002	1.1
OEL	83	0.002	0.3
PRV	48	0.0088	0.8
Total			9.8

^a Component counts from Table 9-9.

^b TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service.

^c VOC emissions are the baseline which were calculated using 0.193 weight ratio for VOC/TOC obtained from the 2011 Gas Composition Memorandum.

9.3 Available Controls and Regulatory Approaches

9.3.1 Available VOC Emission Control Options

The EPA has determined that fugitive emissions from components are a significant source of VOC emissions from well sites and gathering and boosting stations. Based on the review of public and peer review comments on the equipment leaks white paper and the Colorado and Wyoming state rules, the EPA has identified two options for reducing fugitive VOC emissions from components: a fugitive emissions monitoring program based on the use of OGI leak detection combined with repair of fugitive emission components, and a leak monitoring program based on individual component monitoring using Method 21 for leak detection combined with repair of fugitive emission components. These options, as currently being used by industry to reduce fugitive emissions in the oil and natural gas industry, are described below.

9.3.1.1 *Fugitive Emission Detection and Repair with Optical Gas Imaging* Description

The reduction of fugitive emissions from oil and natural gas well sites and gathering and boosting stations involves the development and implementation of a fugitive emissions monitoring plan that covers the collection of fugitive emissions components at well sites or gathering and boosting stations. Under this option, monitoring is conducted using OGI, and the company develops and implements a monitoring plan that covers the collection of fugitive

emissions components at well sites or compressor stations within a company-defined area. An example monitoring plan would include inspection of the collection of all fugitive emissions components, such as connectors, open-ended lines/valves, pressure relief devices, closed vent systems, compressors, and thief hatches on controlled storage vessels. The plan would include provisions to repair or replace fugitive emissions components if evidence of fugitive emissions is discovered during the OGI survey (e.g., any visible emissions from a fugitive emissions component observed using OGI).

Control Effectiveness

Potential emission reduction percentages from the implementation of an OGI monitoring program varies from 40 to 99 percent.¹⁴⁶ The data supporting these emission reduction percentages are based on the gathering of individual OGI surveys at various oil and natural gas industry segment sites. The variation in the percent reductions from these OGI surveys generally depended on whether large fugitive emission sources were found (e.g., open thief hatches, open dump valves, etc.) during the OGI survey and assumptions made by the authors. However, the studies supporting these emission reduction percentages did not provide information on the potential emission reductions from the implementation of an annual, semiannual, quarterly, or monthly OGI monitoring and repair program. A report was found, after the publication of the white paper, from the Colorado Air Quality Control Commission,¹⁴⁷ which estimated (1) 40 percent reduction for annual OGI monitoring for well production tank batteries with uncontrolled VOC emissions of greater than 6 tpy or less than or equal to 12 tpy; (2) 60 percent reduction for quarterly OGI monitoring for well production tank batteries with uncontrolled VOC emissions of greater than 12 tpy and less than or equal to 50 tpy; and (3) 80 percent reduction for monthly OGI monitoring at well production tank batteries with uncontrolled VOC emissions greater than 50 tpy.

From the review of the studies in the white paper and the Colorado Economic Impact Analysis, we expect the emission reductions from the implementation of an OGI monitoring and repair program to vary depending on the frequency of monitoring. As noted above, Colorado

¹⁴⁶ U.S. Environmental Protection Agency. *Oil and Natural Gas Sector Leaks*, Office of Air Quality Planning and Standards. Research Triangle Park, NC. April 2014. Available at <http://www.epa.gov/airquality/oilandgas/2014papers>.

¹⁴⁷ Colorado Air Quality Control Commission, *Cost-Benefit Analysis Submitted Per § 24-4-103(2.5), C.R.S. For Proposed Revisions to Colorado Air Quality Control Commission Regulations Number 3 (5 CCR 1001-5) and Regulation Number 7 (5 CCR 1001-9)*. February 7, 2014.

estimated that monthly monitoring would achieve 80 percent at well production tank batteries with an uncontrolled VOC emission rate of greater than 50 tpy. We believe, based on our review of the studies, monthly monitoring should achieve much higher emission reductions. Based on information in the studies and EPA's engineering judgment, the potential emission reduction percentages are estimated to be 40 percent for annual monitoring, 60 percent for semiannual monitoring, and 80 percent for quarterly monitoring.

Data from the EPA Protocol document estimates monthly Method 21 monitoring to achieve 87 percent reductions at a leak definition of 10,000 ppm and 92 percent reductions at a leak definition of 500 ppm. Potential emission reductions for annual, semiannual and quarterly monitoring frequencies were calculated using the data from the EPA Protocol document.¹⁴⁸ For quarterly monitoring, the Method 21 data from the EPA Protocol document estimates a 67 percent reduction at a leak definition of 10,000 ppm and an 83 percent reduction at a leak definition of 500 ppm. Using Method 21 data from the EPA Protocol document, we estimated the percent reductions from semiannual monitoring to be 55 percent at a leak definition of 10,000 ppm and 75 percent reduction at a leak definition of 500 ppm. The potential emission reduction percentages for annual monitoring were calculated to be 42 percent at a leak definition of 10,000 ppm and 68 percent at a leak definition of 500 ppm. The OGI camera is capable of viewing leaks at a 500 ppm level, and achieves similar emission reductions as a Method 21 monitoring program. Based on this information, we believe the expected emission reductions from an OGI monitoring and repair program falls somewhere in the 500 and 10,000 ppm range found in the Method 21 monitoring programs, but closer to the 500 ppm level.

A study performed by ICF¹⁴⁹ using data from subpart W, EPA/ GRI, City of Fort Worth Natural Gas Air Quality Study, UT Study - Methane Emissions in the Natural Gas Supply Chain: Production, UT Study - Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States Pneumatic Controllers, and Jonah Energy LLC WCCA Spring Meeting Presentation determined the Year 3 fugitive emission reductions from a quarterly LDAR program to be 78 percent. The data provided in the study supports 40, 60, 80 percent emission reductions for annual, semiannual and quarterly monitoring, respectively.

¹⁴⁸ Memorandum from Bradley Nelson, EC/R to Jodi Howard, EPA/OAQPS/SPPD, *Estimation of Potential Emission Reductions with the Implementation of a Method 21 Monitoring Program*. April 25, 2016.

¹⁴⁹ ICF International. *Leak Detection and Repair Cost-Effectiveness Analysis*. Prepared for Environmental Defense Fund. December 4, 2015. Revised May 2, 2016.

On the basis of the analysis and the data described here, it was concluded that an OGI monitoring program in combination with a repair program can reduce fugitive methane and VOC emissions from these segments by 40 percent on an annual frequency, 60 percent on a semiannual frequency and 80 percent on a quarterly frequency, as well as minimize the loss of salable gas.

To be conservative, we performed a sensitivity analysis using the midpoint between the potential emission reductions that were calculated for each of the Method 21 monitoring frequencies at leak definitions of 10,000 ppm and 500 ppm, which were determined to be 55, 65, and 75 percent for annual, semiannual and quarterly monitoring, respectively. We then compared the potential emission reductions from 40, 60, 80 percent reductions with the Method 21 midpoint reduction percentages of 55, 65 and 75 and found that the annual methane and VOC emission reductions at each of the monitoring frequency intervals were comparable.¹⁵⁰

Cost Impacts

Costs (2012 dollars) for preparing an OGI emission monitoring and repair plan for a company-defined area (i.e., field or district) were estimated using hourly estimates for each of the monitoring and repair plan elements. The costs are based on the following assumptions:

- (1) Labor cost for each of the monitoring plan elements was estimated to be \$57.80 per hour.
- (2) Reading of the rule and instructions would take one person four hours to complete at a cost of \$231.
- (3) Development of a fugitive emission monitoring plan would take two and one half people a total of 60 hours to complete at a cost of \$3,468.
- (4) Initial activities planning are estimated to take two people a total of 8 hours per monitoring event. Cost for annual monitoring was estimated to be \$925, semiannual monitoring was estimated to be \$1,850, and quarterly monitoring was estimated to be \$3,699.
- (5) Notification of compliance status was estimated to take one person one hour to complete at a cost of \$58 for gathering and boosting stations. For companies that own and operate well sites, the cost of the notification of compliance was estimated to be \$58 per well site

¹⁵⁰ See Emission Reduction Comparison – Well Sites.xls, and Emission Reduction Comparison – Compressor Stations.xls in Docket Id. No. EPA-HQ-OAR-2015-0216 for more information.

for each company defined area, which is estimated to operate 22 well sites within the defined area for a total of \$1,272.

- (6) Cost of a Method 21 monitoring device of \$10,800; or cost for OGI monitoring using an outside contractor (assumed to be \$600 for a well site and \$2,300 for a gathering and boosting station for each survey).

Costs for implementing a fugitive emission monitoring plan for a company-defined area (i.e., field or district) were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:

- (1) Subsequent activities planning are estimated to take two people a total of 16 hours per monitoring event for well sites and two people a total of 24 hours for gathering and boosting stations. For well sites, this cost was divided among the total number of well sites in the company-defined area.
- (2) The cost for OGI monitoring using an outside contractor was assumed to be \$600 for a well site and \$2,300 for a gathering and boosting station for each survey.
- (3) Annual repair costs were estimated to be \$299 for well sites and \$3,436 for gathering and boosting stations per survey. These costs were estimated assuming that 1.18 percent of the components leak and 75 percent are repaired online and 25 percent are repaired offline.
- (4) Cost for resurvey of components assumes five minutes per leak at \$57.80 per hour for well sites and \$2.00 per leak for gathering and boosting stations. This is based on the assumption that a company purchases Method 21 instrumentation (estimated to be \$10,800¹⁵¹) and is able to perform the resurvey without needing contractors.
- (5) Preparation of annual reports was estimated to take one person a total of 4 hours to complete at a cost of \$231.

The initial setup cost or capital cost for well sites was calculated by summing up the costs for reading the air agency rule, development of fugitive emissions monitoring plan, initial activities planning, and notification of initial compliance status. The total capital cost of these activities was calculated to be \$16,696 per company-defined areas for annual monitoring,

¹⁵¹ Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180.

\$17,620 per company-defined areas for semiannual monitoring and \$19,470 per company-defined areas for quarterly monitoring. Assuming that each company owns and operates 22 well sites within a company-defined area¹⁵², the capital cost per well site was estimated to be \$759 for annual monitoring, \$801 for semiannual monitoring and \$855 for quarterly monitoring. For gathering and boosting stations, the capital cost for reading the rule, development of fugitive emissions monitoring plan, initial activities planning notification of initial compliance status, and purchase of a Method 21 instrumentation device was calculated to be \$16,753 per facility. For gathering and boosting stations, the capital cost was assumed to be shared with other gathering and boosting stations within the company-defined area. These stations are estimated to be approximately 70 miles apart. Therefore, within a 210 mile radius of a central location, there would be an estimated seven gathering and boosting stations, and the capital cost for each of these stations was estimated to be \$2,393.

For well sites and gathering and boosting stations, the annual cost includes: subsequent activities planning, OGI survey by an outside contractor, cost of repair of fugitive emissions found, preparation and submittal of an annual report and the amortized capital cost over 8 years at 7 percent interest. For our analyses, we calculated the annual cost for annual, semiannual and quarterly OGI surveys. The annual cost for annual, semiannual, and quarterly OGI surveying (inclusive of contractor costs, cost of repair of fugitive emissions found, preparation and submittal of an annual report, and amortized capital cost over 8 years at 7 percent interest) was calculated for the production and processing segments. Tables 9-11 through 9-13 present summaries of the cost of control for VOC for the three OGI monitoring frequency options (i.e., annual, semiannual and quarterly).

¹⁵² The number of well sites owned and operated by companies was calculated using data from the Fort Worth study.

Table 9-11. Summary of the Model Plant VOC Cost of Control for the Annual OGI Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) ^a	Capital Cost (\$2012) ^b	Annual Cost (\$2012/year) ^c		Cost of Control (\$2012/ton)	
			Without savings	With savings ^d	Without savings	With savings ^d
Natural Gas Well Site	0.61	\$759	\$1,318	\$809	\$2,158	\$1,324
Oil Well Site (GOR < 300)	0.13	\$759	\$1,318	\$1,204	\$9,953	\$9,089
Oil Well Site (GOR ≥ 300)	0.30	\$759	\$1,318	\$1,063	\$4,380	\$3,533
Gathering and Boosting Station	3.91	\$2,393	\$7,777	\$4,518	\$1,990	\$1,156

^a Assumes 40 percent reduction with the implementation of annual IR camera monitoring.

^b The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program divided between an average of 22 well sites per company district. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between seven stations within a company-defined area.

^c Annual cost for well sites includes annual monitoring and repair cost of \$1,191 and amortization of the capital cost over 8 years at 7 percent interest. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of \$7,736 and amortization of the capital cost over 8 years at 7 percent interest.

^d Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

Table 9-12. Summary of the Model Plant VOC Cost of Control for the Semiannual OGI Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) ^a	Capital Cost (\$2012) ^b	Annual Cost (\$2012/year) ^c		Cost of Control (\$2012/ton)	
			Without savings	With savings ^d	Without savings	With savings ^d
Natural Gas Well Site	0.917	\$801	\$2,285	\$1,521	\$2,494	\$1,660
Oil Well Site (GOR < 300)	0.199	\$801	\$2,285	\$2,114	\$11,503	\$10,639
Oil Well Site (GOR ≥ 300)	0.451	\$801	\$2,285	\$1,903	\$5,062	\$4,215
Gathering and Boosting Station	5.86	\$2,393	\$13,534	\$8,646	\$2,309	\$1,475

^a Assumes 60 percent reduction with the implementation of semiannual IR camera monitoring.

^b The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program divided between an average of 22 well sites per company district. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between seven stations within a company-defined area.

^c Annual cost for well sites includes annual monitoring and repair cost of \$2,151 and amortization of the capital cost over 8 years at 7 percent interest. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of \$13,133 and amortization of the capital cost over 8 years at 7 percent interest.

^d Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

Table 9-13. Summary of the Model Plant VOC Cost of Control for the Quarterly OGI Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) ^a	Capital Cost (\$2012) ^b	Annual Cost (\$2012/year) ^c		Cost of Control (\$2012/ton)	
			Without savings	With savings ^d	Without savings	With savings ^d
Natural Gas Well Site	1.222	\$885	\$4,220	\$3,201	\$3,453	\$2,619
Oil Well Site (GOR < 300)	0.265	\$885	\$4,220	\$3,991	\$15,929	\$15,064
Oil Well Site (GOR ≥ 300)	0.602	\$885	\$4,220	\$3,710	\$7,010	\$6,163
Gathering and Boosting Station	7.81	\$2,393	\$25,049	\$18,532	\$3,205	\$2,371

^a Assumes 80 percent reduction with the implementation of quarterly IR camera monitoring.

^b The capital cost for oil and natural gas production well sites includes the cost of implementing the monitoring program of \$19,470 divided between an average of 22 well sites per company. The capital cost for implementing the monitoring program at gathering and boosting stations was divided between seven stations within a company-defined area.

^c Annual cost for well sites includes annual monitoring and repair cost of \$4,071 and amortization of the capital cost over 8 years at 7 percent interest. Annual cost for gathering and boosting stations includes annual monitoring and repair cost of \$24,649 and amortization of the capital cost over 8 years at 7 percent interest.

^d Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

9.3.1.2 Fugitive Emission Detection and Correction with Method 21

Description

Another option that can be used to reduce fugitive emissions from well sites and gathering and boosting stations involves the development of a fugitive emissions monitoring plan using Method 21 to detect leaks from equipment and components. The plan would incorporate surveying of components at a specified interval and repair threshold using a Method 21 instrument, which also includes following the Method 21 requirements for monitoring, along with repair, recordkeeping and reporting requirements.

The plan would also include provisions for repair or replacement of components if evidence of fugitive emissions are discovered during the survey. The monitoring plan would include inspection of all fugitive emission components and would require repair where evidence

of fugitive emissions is discovered (as soon as practicable, but generally no later than 30 calendar days after the Method 21 survey). In addition, all repairs or replacement of components would be re-surveyed immediately after repair or replacement to ensure the fugitive emissions are below the specified repair threshold.

A facility can use a company-defined area fugitive emissions monitoring plan that covers the collection of fugitive emission components at well sites and gathering and boosting stations. By using a company-defined area, owners and operators have flexibility in developing monitoring plans and determining which company-defined area can be covered under the specifications outlined in one monitoring plan, for ease of implementation and compliance.

Control Effectiveness

Potential control efficiencies for Method 21 monitoring were estimated to be 42 to 83 percent depending on repair threshold and monitoring frequency in the 2016 NSPS. The Method 21 control options included repair thresholds of 10,000 and 500 parts per million (ppm) and annual, semiannual, and quarterly monitoring frequencies. Tables 9-14 through 9-16 present the summaries of the estimated emission reductions for annual, semiannual and quarterly Method 21 monitoring for the two repair thresholds for the well site and the gathering and boosting station model plants.

Cost Impacts

Costs (2012 dollars) for preparing and implementing a fugitive emission monitoring plan for a company-defined area (i.e., field or district) were estimated using hourly estimates for each of the plan elements. The costs are based on the following assumptions:

- (1) Labor cost for each of the monitoring plan elements was estimated to be \$57.80 per hour.
- (2) Reading of the air agency rule and instructions would take one person four hours to complete at a cost of \$231.20.
- (3) Development of a fugitive emission monitoring plan would take two and one half people a total of 60 hours to complete at a cost of \$3,468.
- (4) Initial activities planning are estimated to take two people a total of 16 hours per monitoring event. Cost for annual monitoring was estimated to be \$925, semiannual monitoring was estimated to be \$1,850, and quarterly monitoring was estimated to be \$3,699.

Table 9-14. Summary of the Model Plant VOC Cost of Control for the Annual Method 21 Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) ^a	Capital Cost (\$2012) ^b	Annual Cost (\$2012/year) ^c		Cost of Control (\$2012/ton)	
			Without savings	With savings ^d	Without savings	With savings ^d
10,000 ppm Repair Threshold						
Natural Gas Well Site	.645	\$1,418	\$2,300	\$1,762	\$3,568	\$2,734
Oil Well Site (GOR < 300)	0.14	\$1,418	\$2,300	\$2,179	\$16,459	\$15,595
Oil Well Site (GOR ≥ 300)	0.318	\$1,418	\$2,300	\$2,031	\$7,243	\$6,396
Gathering and Boosting Station	4.12	\$4,283	\$9,803	\$6,365	\$2,378	\$1,544
500 ppm Repair Threshold						
Natural Gas Well Site	1.043	\$1,418	\$2,300	1,430	\$2,204	\$1,371
Oil Well Site (GOR < 300)	0.226	\$1,418	\$2,300	\$2,104	\$10,169	\$9,305
Oil Well Site (GOR ≥ 300)	0.514	\$1,418	\$2,300	\$1,865	\$4,475	\$3,628
Gathering and Boosting Station	6.67	\$4,283	\$9,803	\$4,239	\$1,469	\$635

^a Assumes 42 percent reduction at 10,000 ppm repair threshold and 68 percent reduction at 500 ppm repair threshold with the implementation of annual Method 21 monitoring.

^b The capital cost for oil and natural gas well sites and gathering and boosting stations includes the cost of implementing the monitoring program which includes reading the rule, developing and implementing a monitoring plan (including initial activities planning), notification of initial compliance status, and purchase of a Method 21 monitoring device.

^c Annual cost for oil and natural gas well sites and gathering and boosting stations includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7 percent interest.

^d Recovery credits for oil and natural gas well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

Table 9-15. Summary of the Model Plant VOC Cost of Control for the Semiannual Method 21 Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) ^a	Capital Cost (\$2012) ^b	Annual Cost (\$2012/year) ^c		Cost of Control (\$2012/ton)	
			Without savings	With savings ^d	Without savings	With savings ^d
10,000 ppm Repair Threshold						
Natural Gas Well Site	0.837	\$1,460	\$3,907	\$3,209	\$4,667	\$3,833
Oil Well Site (GOR < 300)	0.181	\$1,460	\$3,907	\$3,750	\$21,530	\$20,666
Oil Well Site (GOR ≥ 300)	0.412	\$1,460	\$3,907	\$3,558	\$9,475	\$8,628
Gathering and Boosting Station	5.35	\$4,415	\$17,292	\$12,828	\$3,230	\$2,396
500 ppm Repair Threshold						
Natural Gas Well Site	1.152	\$1,460	\$3,907	\$2,946	\$3,392	\$2,558
Oil Well Site (GOR < 300)	0.250	\$1,460	\$3,907	\$3,691	\$15,648	\$14,784
Oil Well Site (GOR ≥ 300)	0.567	\$1,460	\$3,907	\$3,426	\$6,887	\$6,039
Gathering and Boosting Station	7.37	\$4,415	\$17,292	\$11,150	\$2,348	\$1,514

^a Assumes 55 percent reduction at 10,000 ppm repair threshold and 75 percent reduction at 500 ppm repair threshold with the implementation of semiannual Method 21 monitoring.

^b The capital cost for oil and natural gas well sites and gathering and boosting stations includes the cost of implementing the monitoring program, which includes reading the rule, developing and implementing a monitoring plan (including initial activities planning), notification of initial compliance status, and purchase of a Method 21 monitoring device.

^c Annual cost for oil and natural gas well sites and gathering and boosting stations includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7 percent interest.

^d Recovery credits for oil and natural gas well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

Table 9-16. Summary of the Model Plant VOC Cost of Control for the Quarterly Method 21 Monitoring Option

Model Plant	Annual VOC Emission Reductions (tpy) ^a	Capital Cost (\$2012) ^b	Annual Cost (\$2012/year) ^c		Cost of Control (\$2012/ton)	
			Without savings	With savings ^d	Without savings	With savings ^d
10,000 ppm Repair Threshold						
Natural Gas Well Site	1.030	\$1,544	\$7,121	\$6,262	\$6,196	\$6,083
Oil Well Site (GOR < 300)	0.223	\$1,544	\$7,121	\$6,928	\$31,906	\$31,042
Oil Well Site (GOR ≥ 300)	0.507	\$1,544	\$7,121	\$6,691	\$14,042	\$13,195
Gathering and Boosting Station	6.58	\$4,679	\$32,271	\$26,780	4,901	\$4,067
500 ppm Repair Threshold						
Natural Gas Well Site	1.26	\$1,544	\$7,121	\$6,070	\$5,651	\$4,817
Oil Well Site (GOR < 300)	0.273	\$1,544	\$7,121	\$6,885	\$26,067	\$25,202
Oil Well Site (GOR ≥ 300)	0.621	\$1,544	\$7,121	\$6,595	\$11,472	\$10,624
Gathering and Boosting Station	8.06	\$4,679	\$32,271	\$25,550	\$4,004	\$3,170

^a Assumes 67 percent reduction at 10,000 ppm repair threshold and 83 percent reduction at 500 ppm repair threshold with the implementation of quarterly Method 21 monitoring.

^b The capital cost for oil and natural gas well sites includes the cost of implementing the monitoring program of \$32,120 divided by an average of 22 well sites per company.

^c Annual cost for oil and natural gas well sites and gathering and boosting stations includes annual monitoring and repair cost and amortization of the capital cost over 8 years at 7 percent interest.

^d Recovery credits for oil and natural gas well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9 percent of natural gas composition, and the value of the natural gas recovered as \$4 Mcf.

- (5) Notification of compliance status was estimated to take one person one hour to complete at a cost of \$58 for gathering and boosting stations. For companies that own and operate well sites, the cost of the notification of compliance was estimated to be \$58 per well site for each company-defined area, which is estimated to operate 22 well sites within the defined area for a total of \$1,272.
- (6) Cost of a Method 21 monitoring device and data collection system was estimated at \$25,300 per company (\$10,800 for the M21 monitoring device and \$14,500 for the data collection system).

Costs for implementing a fugitive emission monitoring plan for a company-defined area for well sites and gathering and boosting stations were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:

- (1) Subsequent activities planning are estimated to take two people a total of 16 hours per monitoring event for well sites and two people a total of 24 hours for gathering and boosting stations. For well sites, this cost was divided among the total number of well sites in the company-defined area.
- (2) Method 21 monitoring was estimated to take two people a total of 16 hours to survey a well production site at a cost of \$925 per survey. For gathering and boosting stations, Method 21 monitoring was estimated to take 2 people a total of 8 hours to survey the station at a cost of \$925 per survey.
- (3) Annual repair costs for well sites were estimated to be \$299 using a repair threshold of 10,000 ppm and \$5,400 using a repair threshold of 500 ppm. These costs were estimated assuming that 1.18 percent of the components leak. The repair costs assume 75 percent are repaired online and 25 percent are repaired offline.
- (4) Annual repair costs for gathering and boosting stations were estimated to be \$3,436 using a repair threshold of 10,000 ppm and \$52,900 using a repair threshold of 500 ppm. These costs were estimated assuming that 1.18 percent of the components leak. The repair costs assume 75 percent are repaired online and 25 percent are repaired offline.
- (5) Cost for resurvey of components assumes 5 minutes per leak at \$57.80 per hour for well sites and \$2.00 per leak for gathering and boosting stations.
- (6) Preparation of annual reports was estimated to take 1 person a total of 4 hours to complete at a cost of \$231.

The initial setup cost or capital cost for oil and natural gas well sites was calculated by summing up the costs for reading the rule, development of fugitive emissions monitoring plan, initial activities planning, acquisition of a Method 21 monitoring device and data collection system and notification of initial compliance status. The total capital cost of these activities was estimated to be \$31,196 for annual monitoring, \$32,120 for semiannual monitoring, and \$33,970 for quarterly monitoring. Assuming that each company owns and operates 22 well sites within a company-defined area, the capital cost per well site was estimated to be \$1,460.

For gathering and boosting stations, the capital cost was assumed to be shared with other gathering and boosting stations within the company-defined area. These stations are estimated to be approximately 70 miles apart. Therefore, within a 210-mile radius of a central location, there would be an estimated seven gathering and boosting stations and the capital cost for these stations was estimated to be \$29,982 for annual monitoring, \$30,907 for semiannual monitoring, and \$32,756 for quarterly monitoring. Assuming that there are 7 gathering and boosting stations in a company-defined area, the capital cost per station was estimated to be \$4,283 for annual monitoring, \$4,415 for semiannual monitoring, and \$4,679 for quarterly monitoring.

For oil and natural gas well sites and gathering and boosting stations, the annual cost includes: subsequent activities planning, Method 21 survey, cost of repair of fugitive emissions found, preparation and submittal of an annual report, and the amortized capital cost over 8 years at 7 percent interest. The annual cost for annual, semiannual, and quarterly Method 21 surveying (inclusive of cost of repair of fugitive emissions found, preparation and submittal of an annual report, and amortized capital cost over 8 years at 7 percent interest) was calculated for each of the industry segments. Tables 9-14 through 9-16 present summaries of the cost of control for VOC at each of the repair thresholds (i.e., 10,000 and 500 ppm) for the three monitoring frequency options (i.e., annual, semiannual and quarterly).

9.3.2 Existing Federal, State and Local Regulations

9.3.2.1 *Federal Regulations that Specifically Require Control of VOC Emissions*

For each well site and compressor station (including gathering and boosting stations), the EPA has finalized NSPS requirements that will require the development of a fugitive emissions monitoring plan that includes semiannual monitoring for well sites and quarterly monitoring for

compressor stations by OGI and repair of leaking fugitive emission components. Method 21 can be used as an alternative to OGI at a 500 ppm repair threshold.

9.3.2.2 *State and Local Regulations that Specifically Require Control of VOC Emissions*

States or local air districts may have regulations or permitting restrictions on VOC emissions that may apply to an emission source as a result of an operating permit, or preconstruction permit based on air quality maintenance or improvement goals of an area. Permits specify what construction is allowed, what emission limits must be met, and often how the source must be operated. To ensure that sources follow the permit requirements, permits also contain monitoring, recordkeeping and reporting requirements. A summary of some of the existing state regulations and permit programs that apply to the oil and natural gas industry is provided below.

Colorado Regulation 7

The State of Colorado has regulations that require leak inspections at all well sites, compressor stations upstream of the processing plant and storage vessels. For well production facilities and compressor stations, the monitoring frequency is determined by the estimated uncontrolled actual VOC emissions leak from the highest emitting tank or, if no tanks are present, the controlled actual emissions from all permanent equipment. The monitoring frequency for fugitives at well production facilities varies depending on emissions. There is a one-time inspection (0-6 tpy VOC), annual inspections (6-12 tpy VOC), quarterly inspections (12-20 tpy VOC w/o tanks, 12-50 w/ tanks), or monthly inspections (> 20 TPY VOC w/o tanks, > 50 tpy VOC w/ tanks). Monthly AVO inspections are also required for well production facilities that do one-time, annual, and quarterly monitoring. For compressor stations, the monitoring frequency is annual (0-12 tpy VOC), quarterly (12-50 tpy VOC), or monthly (> 50 tpy VOC). A leak is defined as hydrocarbon concentration greater than 500 ppm. These regulations allow OGI inspections, Method 21 or other “[d]ivision approved instrument based monitoring device or method” to detect leaks (Colorado Department of Public Health and Environment, Air Quality Control Commission, Regulation Number 7). The first attempt to repair leaks found during monitoring must be made no later than five working days after discovery, unless parts are unavailable or the equipment requires shutdown to complete repair. If

parts are unavailable, they must be ordered promptly and the repair must be made within 15 working days of receipt of the parts. If a shutdown is required, the leak must be repaired during the next scheduled shutdown.

Wyoming Chapter 8

The Wyoming Department of Environmental Quality issued regulations in June 2015 for existing (as of January 1, 2014) PAD facility (location where more than one well and/or associated production equipment are located, where some or all production equipment is shared by more than one well or where well streams from more than one well are routed through individual production trains at the same location) and single-well oil and gas production facilities or sources, and all compressor stations that are located in the Upper Green River Basin (UGRB) ozone nonattainment area¹⁵³. The rule requires operators with fugitive emissions greater than or equal to 4 tons per year of VOC to develop and implement an LDAR protocol by January 1, 2017. Operators must monitor components (flanges, connectors (other than flanges), open-ended lines, pumps, valves, and “other” components listed in Table 2-4 of the EPA’s Protocol for Equipment Leak Emissions Estimates) quarterly using a combination of Method 21, IR camera, other instrument based technologies, or AVO inspections. However, an LDAR protocol consisting of only AVO inspections does not meet the requirements of the rule. No specific repair timeframes are included in the regulation.

Utah General Approval Order

The Utah Department of Environmental Quality approved a “General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery” on June 5, 2014¹⁵⁴. This General Approval Order (GAO) requires LDAR for equipment (e.g., valve, flange or other connection, pump, compressor, pressure relief device or other vent, process drain, open-ended valve, pump seal, compressor seal, and access door seal or other seal that contains or contacts a process stream with hydrocarbons) based on annual throughput of crude oil and condensate. Annual inspections are required for sources that have a projected annual throughput of crude oil and condensate combined that is greater than or equal to 10,000 barrels or for sources that do not

¹⁵³ Wyoming regulations are available at <http://soswy.state.wy.us/Rules/RULES/9868.pdf>.

¹⁵⁴ Utah regulations are available at <http://www.deq.utah.gov/Permits/GAOs/docs/2014/6June/DAQE-AN149250001-14.pdf>.

have a crude oil or condensate storage tank onsite, and quarterly inspections are required for sources that have a projected annual throughput of crude oil and condensate combined that is greater than or equal to 25,000 barrels. For sources performing quarterly monitoring, provisions are provided for less frequent monitoring if no leaks are found during a year of monitoring. Repairs must be made within 15 days of finding a leak. A delay of repair is allowed if replacement parts are unavailable (must order parts within 5 days of detection and repair leak within 15 days after receipt of the parts) or technically infeasible to repair without a shutdown (shutdown must occur within 6 months of finding leak or operators must demonstrate emissions from shutdown would be greater than the uncontrolled leaking component).

The monitoring can be performed using Method 21, a tunable diode laser absorption spectroscopy (TDLAS) or an IR camera. A leak is defined as a reading of 500 ppm with Method 21 analyzer or TDLAS, or visible leak with IR camera.

Ohio General Permit

The Ohio EPA approved two types of general permits in May 2014 for oil and gas well site production operations (small flares and large flares) and high volume horizontal hydraulic fracturing for facilities that emit less than 1 ton per year of any toxic air contaminant (not including HAP emitting sources that are subject to MACT subpart HH)¹⁵⁵. Each permittee is required to develop and implement an LDAR program for ancillary equipment (pumps, compressors, pressure relief devices, connectors, valves, flanges, vents, covers, any bypass in a closed vent system, and each storage vessel) that requires monitoring using a forward looking infrared (FLIR) camera or Method 21. Leak definitions vary depending on component (most are 500 or 10,000 ppm). Quarterly monitoring is required for the first year and varies after that depending on performance. Repairs must be made within 30 days of finding a leak but if leaks cannot be repaired within that time frame, the general permit references the delay of repair provisions allowed under NSPS subpart VVa.

Ohio has also proposed a general permit for natural gas compressor stations that have the potential to leak greater than 10 tons per year of VOC. The general permit requirements for

¹⁵⁵ Ohio regulations available at http://www.epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1_PTIOA20140403final.pdf
<http://epa.ohio.gov/dapc/genpermit/genpermits.aspx#127854016-available-permits>.

compressor stations are similar to the LDAR requirements for oil and gas well site production operations. No emissions data were available for this LDAR program.

Pennsylvania General Permit 5 and Exemption Category No. 38

General Permit 5 is a General Plan Approval and/or General Operating Permit for midstream natural gas gathering, compression and/or processing facilities that are minor air contamination facilities¹⁵⁶. Exemption Category No. 38 of the Air Quality Permit Exemption List applies to sources located at a well pad¹⁵⁷. The general permit requires operators to conduct leak detection and repair programs monthly using AVO methods. Equipment to be monitored include: valves, flanges, connectors, storage vessels/storage tanks, and compressor seals. In addition, the general permit requires annual monitoring at wells and quarterly monitoring for compression and processing facilities. Operators must use a FLIR camera or approved device to detect gaseous hydrocarbons leaks. All leaks at production sites, compressor stations or processing facilities must be repaired within 15 days of finding the leak.

West Virginia Class II General Permit G70-B

General Permit G70-B is for natural gas production facilities¹⁵⁸. The permit requires quarterly monitoring using AVO, Method 21 analyzers, IR cameras, or some combination. The AVO inspection shall include, but not be limited to, defects as visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. If a Method 21 analyzer is used, a leak (fugitive emissions of regulated air pollutants) is defined as no detectable emissions (less than 500 ppm). If an IR camera is used, no detectable emissions is defined as no visible leaks detected in accordance with U.S. EPA alternative IR camera work practices (40 CFR 60, subpart A). The first attempt at repair must be made within 5 calendar days of discovering the leak, and the final repair must be made within 15 calendar days of discovering the leak. No emissions data are available for this LDAR program.

¹⁵⁶ Pennsylvania regulations are available at http://www.dep.state.pa.us/dep/deputate/airwaste/aq/permits/gp/GP-5_2-25-2013.pdf.

¹⁵⁷ Pennsylvania regulations are available at <http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf>.

¹⁵⁸ West Virginia regulations are available at <http://www.dep.wv.gov/daq/permitting/Documents/G70-B%20Final/G70-B%20General%20Permit%20Signed2.pdf>.

San Joaquin Valley Air Pollution Control District Rule 4409

The San Joaquin Valley Air Pollution Control District requires the development of an operator management plan that establishes inspection, replacement, re-inspection requirements, maintenance, repair periods and replacement retrofit requirements for components at light crude oil production facilities, natural gas production facilities and natural gas processing plants¹⁵⁹.

For manned facilities, the District requires owners and operators to audio-visually inspect for leaks daily and, for unmanned sites, the District requires owners and operators to audio-visually inspect for leaks weekly. Additionally, the District requires owners and operators to conduct inspections for leaks quarterly using Method 21. Leaks discovered are required to be repaired within two to seven days of discovery, depending on the magnitude of the leak. An extension of up to seven days is allowed if the leak is minor. Owners and operators are also allowed to apply for written approval to change the Method 21 monitoring inspection frequency from quarterly to annually if they meet specified criteria. Components at oil production facilities and gas production facilities that exclusively handle gas/vapor or liquid with a VOC content of 10 percent by weight or less are exempt from requirements.

9.4 Recommended RACT Level of Control

We evaluated available data obtained in the development of the 2016 NSPS final rule, comments received on the draft CTG and 2015 NSPS proposed rule, and peer review comments received on the EPA's equipment leaks white paper. Based on our evaluation of this data and information about existing regulations that control VOC emissions from oil and natural gas production sites, this CTG provides RACT recommendations for the collection of fugitive emission components at well sites with an average production of greater than 15 barrel equivalents per well per day, and gathering and boosting stations. At this time, this CTG does not include a RACT recommendation for well sites with an average production of less than 15 barrel equivalents per well per day. However, we encourage air agencies to consider site-specific data from these sources in their RACT analyses.

We further recommend that RACT be the implementation of a monitoring plan that includes semiannual monitoring for well sites with a GOR greater than or equal to 300 and quarterly monitoring for gathering and boosting stations using OGI or Method 21 and repair of

¹⁵⁹ San Joaquin Valley APCD regulations available at <http://www.arb.ca.gov/drdb/sju/cur.htm>.

components found to be leaking. The information currently available to EPA does not support applying the RACT recommendations related to fugitive monitoring contained in this chapter of the CTG to well sites with a GOR less than 300.

As discussed in section 9.3.2.2 of this chapter, some existing state and local regulations already require fugitive emissions monitoring of oil and natural gas production sites. The monitoring techniques listed in these requirements include the use of either Method 21 or OGI to locate fugitive emissions from equipment and components. In addition, peer review comments received on the equipment leaks white paper indicate that some companies are voluntarily monitoring their production sites using OGI to eliminate leaks from equipment. Monitoring and repair of equipment and components using OGI or Method 21 are the most viable methods for reducing fugitive emissions from equipment leaks in the production segment of the oil and natural gas industry.

Both Wyoming and Ohio require quarterly monitoring of components at production sites, and the cost of control per ton of VOC reduced is considered reasonable for OGI quarterly monitoring for natural gas well sites (about \$3,450 per ton of VOC reduced). However, based on the information currently available regarding the necessary equipment, trained personnel and the planning necessary to implement a monitoring and repair program, we are concerned about the potential compliance burden that could be associated with quarterly monitoring of the large number of existing well sites. The VOC cost of control for semiannual monitoring using OGI was estimated to be \$2,494 per ton of VOC reduced for natural gas well sites and \$5,062 per ton of VOC reduced for oil wells sites with a GOR greater than or equal to 300.

We do not estimate that there would be a compliance burden associated with quarterly fugitive OGI monitoring at gathering and boosting stations because there are fewer existing gathering and boosting stations than well sites. Moreover, the cost of control per ton of VOC reduced is reasonable for quarterly OGI monitoring. The VOC cost of control for quarterly monitoring using OGI was estimated to be about \$3,200 per ton of VOC reduced for gathering and boosting stations.

For well sites, the cost of control for a monitoring plan using Method 21 with a 10,000 ppm leak detection is generally more costly than the use of OGI where there are a large number of equipment components to be monitored. The cost for a natural gas well site was estimated to be \$4,667 per ton of VOC reduced for semiannual monitoring. The cost for an oil well site with a

GOR greater than 300 was estimated to be \$9,475 per ton of VOC reduced for semiannual monitoring. As shown in section 9.3.1 of this chapter, the cost of control for the 500 ppm repair threshold options are higher than the 10,000 ppm repair threshold option. The use of a monitoring plan using Method 21 with a 10,000 ppm leak detection may, however, be a lower cost alternative to OGI where there are fewer equipment components to be monitored. For gathering and boosting stations, the cost of control for a monitoring plan using Method 21 with a 10,000 ppm leak detection is estimated to be \$3,230 per ton of VOC reduced for semiannual monitoring and \$3,205 for quarterly monitoring. The costs for semiannual monitoring using Method 21 for natural gas well sites, and quarterly monitoring using Method 21 for gathering and boosting stations were considered reasonable (about \$4,670 for gas well sites and \$3,200 for gathering and boosting stations). Based on our analyses that indicates that a monitoring plan using Method 21 at 500 ppm would meet the same level of control as semiannual monitoring using OGI, we recommend that air agencies allow owners and operators to comply by using Method 21 at 500 ppm as an alternative to semiannual monitoring using OGI.

Based on existing state and local fugitive emission requirements, economic feasibility, and the reasonableness of costs, we recommend that RACT for the collection of fugitive emission components at well sites with a GOR greater than or equal to 300 that produce, on average, greater than 15 barrel equivalents per well per day, be the implementation of a fugitive emissions monitoring and repair plan that includes semiannual monitoring using OGI or Method 21. For these same reasons, we recommend that RACT for the collection of fugitive emission components at gathering and boosting stations be the implementation of a fugitive emissions monitoring and repair plan that includes quarterly monitoring using OGI or Method 21.

In summary, we recommend the following RACT for the collection of fugitive emission components at well sites and gathering and boosting stations in the production segment:

- (1) RACT for the Collection of Fugitive Emission Components at Well Sites With a GOR Greater than or Equal to 300, that Produce, on Average, Greater than 15 Barrel Equivalents per Well per Day: We recommend the implementation of a monitoring plan that includes semiannual monitoring using OGI and repair of components that are found to be leaking at well sites. We further recommend that air agencies allow Method 21 with a repair threshold of 500 ppm as an alternative compliance means to OGI. We also

recommend that each fugitive emissions component repaired or replaced be resurveyed to ensure there is no leak after repair or replacement by the use of either Method 21 or OGI no later than 30 days of finding fugitive emissions.

- (2) RACT for the Collection of Fugitive Emission Components at Gathering and Boosting Stations in the Production Segment (Located from the Wellhead to the Point of Custody Transfer to the Natural Gas Transmission and Storage Segment or Oil Pipeline): We recommend the implementation of a monitoring plan that includes quarterly monitoring using OGI and repair of components that are found to be leaking at gathering and boosting stations. We further recommend allowing Method 21 with a repair threshold of 500 ppm as an alternative to OGI. We also recommend that each fugitive emissions component repaired or replaced be resurveyed to ensure there is no leak after repair or replacement by the use of either Method 21 or OGI no later than 30 days of finding fugitive emissions.

9.5 Factors to Consider in Developing Fugitive Emissions RACT Procedures

To ensure that fugitive emissions are properly monitored and repaired (as necessary) under the RACT recommendations, we suggest that air agencies specify OGI/Method 21 monitoring and equipment repair recordkeeping and reporting requirements to document compliance. The appendix to this document presents example model rule language that incorporates the compliance elements recommended in this section that air agencies may choose to use in whole or in part when implementing RACT.

9.5.1 Monitoring Recommendations

We recommend that air agencies require a fugitive emissions OGI/Method 21 monitoring plan that covers fugitive emission component sources that includes basic required monitoring plan elements. We recommend that air agencies require the monitoring plan be developed for a company-defined area and that it cover the collection of fugitive emissions components at well sites and gathering and boosting stations.

We suggest that the fugitive emissions monitoring plan that covers the collection of fugitive emissions components at well sites and gathering and boosting stations within each company-defined area include the following minimum elements:

- (1) Frequency for conducting surveys.
- (2) Technique for determining fugitive emissions.
- (3) Manufacturer and model number of fugitive emissions detection equipment to be used.
- (4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair.
- (5) Procedures and timeframes for verifying fugitive emission component repairs.
- (6) Records that will be kept and the length of time records will be kept.
- (7) If you are using OGI, you should also include the following: (i) Verification that your optical gas imaging equipment meets specification requirements (i.e., capable of imaging gases in a spectral range for the compound of highest concentration in the potential fugitive emissions, must be capable of imaging a gas that is half methane and half propane at a concentration of 10,000 ppm at a flow rate of less than or equal to 60 g/hr from a quarter inch diameter); (ii) Procedure for a daily verification check; (iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained; (iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold; (v) Procedures for conducting surveys; (vi) Training and experience needed prior to performing surveys; including how the operator will (a) ensure an adequate thermal background is present in order to view potential fugitive emissions, (b) deal with adverse monitoring conditions such as wind, (c) deal with interferences; and (vii) Procedures for calibration and maintenance.
- (8) Procedures for calibration and maintenance should comply with those recommended by the manufacturer of monitoring device used.
- (9) If you are using Method 21 of appendix A-7 of part 60, you should also include the following: (i) Verification that your monitoring equipment meets the requirements specified in section 6.0 of Method 21 at 40 CFR part 60, appendix A-7; and (ii) procedures for conducting surveys.

We suggest that you also require the following minimum elements in each fugitive emissions monitoring plan:

- (1) Sitemap.
- (2) A defined observation path that ensures that all fugitive emissions components are within sight of the path. The observation path must account for interferences.
- (3) If you are using Method 21, the plan should also include a list of fugitive emission components to be monitored and method for determining location of fugitive emission components to be monitored in the field (e.g., tagging, identification on a process and instrumentation diagram, etc.).
- (4) Your plan should also include the written plan developed for all of the fugitive emission components designated as difficult-to-monitor and unsafe-to-monitor.

We recommend a monitoring survey of each collection of fugitive emissions components at a well site be conducted semiannually after the initial survey and that consecutive semiannual monitoring surveys be conducted at least four months apart. We recommend a monitoring survey of each collection of fugitive emissions components at a gathering and boosting station be conducted quarterly after the initial survey and that consecutive quarterly monitoring surveys be conducted at least two months apart.

9.5.2 Repair Recommendations

We recommend that air agencies require that any identified source of fugitive emissions identified by using OGI (indicated by visual emissions) or Method 21 instrument (indicated by a concentration of 500 ppm above background) be repaired or replaced as soon as practicable, but no later than 30 calendar days after detection of the fugitive emissions. If the repair or replacement is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next compressor station shutdown, well shutdown, well shut-in, after an unscheduled, planned or emergency vent blowdown or within 2 years, whichever is earlier. We also recommend that repaired or replaced fugitive emission components be required to be resurveyed as soon as practicable, but no later than 30 days after completion of the repair or replacement, to ensure that there is no leak. For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, we recommend that air agencies require that the operator resurvey the repaired fugitive emissions components using Method 21 (or alternative screening procedure based on soap bubble solution method (as specified under section 8.3.3 of Method 21)), or OGI no later than 30 days of being

repaired. A fugitive emissions component is repaired when either the Method 21 instrument indicates a concentration of less than 500 ppm above background, or an OGI instrument shows no indication of visible emissions.

Appendix

We include model rule language in this appendix for our recommended RACT for oil and natural gas industry sources. The intent of this language is to provide regulation language that states can use as a starting point in the development of their SIP. In some cases, the language may need to be revised to make it adequate for SIP approval purposes. Although we include model rule language for closed vent systems, control devices and performance tests (that apply across several model rule requirements for sources), it is acknowledged that states may have existing similar language in their programs that they may want to use in lieu of the model language provided. State implementation plans should specify enforceable test methods.

The model rule language does not specify rule compliance dates. These dates will be determined by air agencies (referred to within the model rule language as the “regulatory authority”). State and local government agencies are encouraged to search this model rule language for places where the “regulatory authority” will need to specify dates (e.g., compliance date) by searching for (“regulatory authority”) in the model rule language.

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A Storage Vessels: VOC Emission Control Requirements

A.1 Applicability

(a) The VOC emissions control requirements of section A apply to each storage vessel located in the oil and natural gas industry (excluding distribution) that has the potential for VOC emissions equal to or greater than 6 tpy. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline established by your regulatory authority. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a federal, state, local or tribal authority. Any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of VOC potential to emit for purposes of determining applicability, provided you comply with the requirements in section A.1(a)(i) through (a)(iv).

(i) You meet the cover requirements specified in section A.2(c).

(ii) You meet the closed vent system requirements specified in section A.2(d).

(iii) You must maintain records that document compliance with paragraphs A.2(c) and (d).

(iv) In the event of removal of apparatus that recovers and routes vapor to a process, or operation that is inconsistent with the conditions specified in paragraphs A.2(c) and (d) of this section, you must determine the storage vessel's potential for VOC emissions according to this section within 30 days of such removal or operation.

(b) A storage vessel with a capacity greater than 100,000 gallons used to recycle water that has been passed through two stage separation is not a storage vessel.

(c) The storage vessel VOC emission control requirements specified in this section do not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, 40 CFR part 63, subparts G, CC, HH, or WW.

A.2 What VOC Emission Control Requirements Apply to Storage Vessels?

For each storage vessel, you must comply with the VOC emission control requirements of paragraphs (a) through (e) in this section by the compliance date established by your regulatory authority. Alternative requirements for storage vessels subject to VOC emission control requirements that meet certain conditions are presented in paragraph (i) of this section. Requirements for storage vessels removed from service are presented in paragraph (j) of this section.

(a) You must reduce VOC emissions from each storage vessel by 95.0 percent, unless you meet the conditions of paragraph (i) of this section.

(b) (1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of paragraph (c) of this section, that is connected through a closed vent system that meets the requirements of paragraph (d) of this section and route to a control device that meets the conditions specified in paragraph (e) of this section, as applicable. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) If you use a floating roof to reduce emissions, you must meet the requirements of 40 CFR 60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

(c) *Cover requirements for storage vessels.* (1) The cover and all openings on the cover (*e.g.*, access hatches, sampling ports, pressure relief valves and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel.

(2) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed vent system, designed and operated in accordance with the requirements of paragraph (d) of this section to a control device or to a process.

(3) Each storage vessel thief hatch shall be equipped, maintained and operated with a weight, or other mechanism, to ensure that the lid remains properly seated and sealed under normal operating conditions, including such times when working, standing/breathing, and flash emissions may be generated. You must select gasket material for the hatch based on composition of the fluid in the storage vessel and weather conditions.

(d) *Closed vent system requirements for storage vessels.* For closed vent system requirements using a control device or routing emissions to a process, you must comply with the following:

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the storage vessel to a control device or to a process that meets the requirements specified in paragraph (e) of this section, or to a process.

(2) You must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual and auditory inspections.

(3) You must meet the requirements specified in paragraph (d)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process.

(i) Except as provided in paragraph (d)(3)(ii) of this section, you must comply with either paragraph (d)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away for the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to section A.5(a)(9).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (d)(3)(i) of this section.

(4) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all emissions from the storage vessel are routed to the control device or to a process and that the control device is of sufficient design and capacity to accommodate all emissions from the storage vessel and have it certified by a qualified professional engineer in accordance with paragraphs (d)(4)(i) and (ii) of this section.

(i) You must provide the following certification, signed and dated by the qualified professional engineer: "I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted and this report was prepared pursuant to the requirements of this rule. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information."

(ii) The assessment shall be prepared under the direction or supervision of the qualified professional engineer who signs the certification in paragraph (d)(4)(i) of this section.

(e) Control device requirements for storage vessels.

(1) Each control device used to meet the emission reduction standard in paragraph (a) of this section for your storage vessel must be installed according to paragraphs (e)(1)(i) through (iv) of this section, as applicable. As an alternative to paragraph (e)(1)(i) of this section, you may install a control device model tested under section F(d), which meets the criteria in section F(d)(11) and meets the continuous compliance requirements in section F(e).

(i) For each enclosed combustion device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) you must follow the requirements in paragraphs (e)(1)(i)(A) through (D) of this section.

(A) Ensure that each enclosed combustion device is maintained in a leak free condition.

(B) Install and operate a continuous burning pilot flame.

(C) Operate the enclosed combustion device with no visible emissions, except for periods not to exceed a total of one minute during any 15 minute period. A visible emissions test using section 11 of EPA Method 22, 40 CFR part 60, appendix A-7, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes. Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection. Following return to operation from maintenance or repair activity, each device must pass a Method 22, 40 CFR part 60, appendix A-7, visual observation as described in this paragraph.

(D) Each enclosed combustion control device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (1) through (4) of this section.

(1) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of section F(b).

(2) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of section F(b).

(3) You must operate at a minimum temperature of 760°Celsius, provided the control device has demonstrated, during the performance test conducted under section F(b), that combustion zone temperature is an indicator of destruction efficiency.

(4) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(ii) Each vapor recovery device (*e.g.*, carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater. A carbon replacement schedule must be included in the design of the carbon adsorption system.

(iii) You must design and operate a flare in accordance with the requirements of 40 CFR 60.18(b), and you must conduct the compliance determination using Method 22, 40 CFR part 60, appendix A-7, to determine visible emissions.

(iv) You must operate each control device used to comply with paragraph (a) of this section at all times when gases, vapors, and fumes are vented from the storage vessel through the closed vent system to the control device. You may vent more than one storage vessel to a control device used to comply with this subpart.

(2) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (e)(2)(i) and (ii) of this section.

(i) Following the initial startup of the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to section F(c)(2) or (3) or according to the design required in paragraph (e)(1)(ii) of this section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in section A.5(a)(10).

(ii) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (e)(2)(ii)(A) through (F) of this section.

(A) Regenerate or reactivate the spent carbon in a thermal treatment unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(B) Regenerate or reactivate the spent carbon in a unit equipped with operating organic air emission controls in accordance with an emissions standard for VOC under a subpart in 40 CFR part 60 or part 63.

(C) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(D) Burn the spent carbon in a hazardous waste boiler or industrial furnace for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(E) Burn the spent carbon in an industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(F) Burn the spent carbon in an industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(f) You must demonstrate initial compliance with the VOC emission reduction requirements that apply to each storage vessel as required in section A.3.

(g) You must demonstrate continuous compliance with the VOC emission control requirements that apply to each storage vessel as required by section A.4.

(h) You must perform the required recordkeeping and reporting as required by section A.5.

(i) *Alternative requirements for storage vessels.* Maintain the uncontrolled actual VOC emissions from the storage vessel subject to VOC emission control requirements at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology. Monthly calculations must be based on the average throughput for the month. Monthly calculations must be separated by at least 14 days. You must comply with paragraph (i)(1) or (2) of this section.

(1) If a well feeding the storage vessel subject to VOC emission control requirements undergoes fracturing or refracturing, you must comply with paragraph (a) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel.

(2) If the monthly emissions determination required in this paragraph indicates that VOC emissions from your storage vessel subject to VOC emission control requirements increases to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel, you must comply with paragraph (a) of this section within 30 days of the monthly calculation.

(j) *Requirements for storage vessels that are removed from service or returned to service.* If you are the owner or operator of a storage vessel subject to the VOC emission control requirements that is removed from service, you must comply with paragraphs (j)(1) and (2) of

this section. A storage vessel is not an affected source under this section for the period that it is removed from service.

(1) For a storage vessel to be removed from service, you must comply with the requirements of paragraph (j)(1)(i) and (ii) of this section.

(i) You must completely empty and degas the storage vessel, such that the storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(ii) You must submit a notification in your next annual report, identifying each storage vessel removed from service during the reporting period and the date of its removal from service.

(2) If a storage vessel subject to VOC emission control requirements identified in paragraph (j)(1) of this section is returned to service during the reporting year, you must submit a notification in your next annual report identifying each storage vessel that has been returned to service and the date of its return to service.

A.3 Initial Compliance Demonstration Requirements

You must demonstrate initial compliance with the VOC emission control requirements for each storage vessel complying with section A.2 by complying with the requirements in paragraphs (a) through (h) of this section.

(a) You determine the potential VOC emission rate as specified in section A.1(a).

(b) You reduce VOC emissions from each storage vessel subject to VOC emission control requirements by 95.0 percent or greater as required in section A.2 and as demonstrated by section F.

(c) If you use a control device to reduce emissions, you must equip your storage vessel with a cover that meets the requirements of section A.2(c) that is connected through a closed vent system that meets the requirements of section A.2(d) and is routed to a control device that

meets the requirements of A.2(e). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(d) You conduct an initial performance test as required in section F within 180 days after the compliance date established by your regulatory authority.

(e) You conduct the initial cover and closed vent system inspections according to the requirements in section A.4(d) within 180 days after the compliance date established by your regulatory authority.

(f) You submit the initial annual report for your storage vessels as required in section A.5(b).

(g) You maintain the records as specified in section A.5(a).

(h) If you comply by using a floating roof, you submit a statement that you are complying with 40 CFR 60.112b(a)(1) or (2) in accordance with section A.2(b)(2) with the initial annual report specified in section A.5(b).

A.4 Continuous Compliance Demonstration Requirements

You have demonstrated continuous compliance for each storage vessel subject to the VOC emission control requirements in section A.2 by meeting the requirements in paragraphs (a) through (f) of this section.

(a) For each storage vessel subject to VOC emission reduction requirements, you must demonstrate continuous compliance according to paragraphs (b) and (c) of this section.

(b) You must reduce VOC emissions from the storage vessel by 95.0 percent or greater.

(c) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of section A.2(e) according to paragraphs (c)(1) through (4) of this section. You are exempt from the requirements of this paragraph if you install a control device model tested in accordance with sections F(d)(2) through (10), which meets the

criteria in section F(d)(11), the reporting requirements in section F(d)(12), and the continuous compliance requirements in F(e).

(1) For each combustion device you must conduct inspections at least once every calendar month according to paragraphs (c)(1)(i) through (iv) of this section. Monthly inspections must be separated by at least 14 calendar days.

(i) Conduct visual inspections to confirm that the pilot is lit when vapors are being routed to the combustion device and that the continuous burning pilot flame is operating properly.

(ii) Conduct inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22, 40 CFR part 60, appendix A-7. The observation period shall be 15 minutes. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period.

(iii) Conduct olfactory, visual and auditory inspections of all equipment associated with the combustion device to ensure system integrity.

(iv) For any absence of pilot flame, or other indication of smoking or improper equipment operation (*e.g.*, visual, audible, or olfactory), you must ensure the equipment is returned to proper operation as soon as practicable after the event occurs. At a minimum, you must perform the procedures specified in paragraphs (c)(1)(iv)(A) and (B) of this section.

(A) You must check the air vent for obstruction. If an obstruction is observed, you must clear the obstruction as soon as practicable.

(B) You must check for liquid reaching the combustor.

(2) For each vapor recovery device, you must conduct inspections at least once every calendar month to ensure physical integrity of the control device according to the manufacturer's instructions. Monthly inspections must be separated by at least 14 calendar days.

(3) Each control device must be operated following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices

for minimizing emissions. Records of the manufacturer's written operating instructions, procedures, and maintenance schedule must be available for inspection as specified by A.5(a)(11).

(4) Conduct a periodic performance test no later than 60 months after the initial performance test as specified in section F(b)(5)(ii) and conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test.

(d) If you install a control device or route emissions to a process, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (d)(1) of this section, inspect each cover according to the procedures and schedule specified in paragraph (d)(2) of this section, and inspect each bypass device according to the procedures of paragraph (d)(3) of this section. You must also comply with the requirements of (d)(4) through (7) of this section.

(1) For each closed vent system, you must conduct an inspection at least once every calendar month as specified in paragraphs (d)(1)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in section A.5(a)(7).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(2) For each cover, you must conduct inspections at least once every calendar month as specified in paragraphs (d)(2)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in section A.5(a)(8).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or

gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.*, fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(3) For each bypass device, except as provided for in section A.2(d)(3)(ii), you must meet the requirements of paragraphs (d)(3)(i) or (ii) of this section.

(i) You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm, or initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is sounded according to section A.5(a)(9).

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections and records of each time the key is checked out, if applicable, according to section A.5(a)(9).

(4) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (d)(4)(i) through (iii) of this section, except as provided in paragraph (d)(5) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 30 calendar days after the leak is detected.

(iii) Grease or another applicable substance must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

(5) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(6) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (d)(6)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (d)(1) and (2) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (d)(1) or (2) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(7) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (d)(7)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (d)(1) and (2) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(e) You must submit the annual reports for your storage vessels as required in section A.5(b).

(f) You must maintain the records as specified in section A.5(a).

A.5 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements.* For each storage vessel, you must maintain the records identified in paragraphs (a)(1) through (12) of this section, as applicable, either onsite or at the nearest local field office for at least five years.

(1) If required to reduce emissions by complying with section A.2(a), the records specified in paragraphs (a)(6) through (8) of this section and sections A.4(d)(6)(ii) and A.4(d)(7)(ii), as applicable.

(2) Records of each VOC emissions determination for each storage vessel made under A.1(a) including identification of the model or calculation methodology used to calculate the VOC emission rate.

(3) Records of deviations in cases where the storage vessel was not operated in compliance with the requirements specified in sections A.2 and F, as applicable.

(4) For storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), records indicating the number of consecutive days that the vessel is located at a site in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment. If a storage vessel is removed from a site and, within 30 days, is either returned to or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the original storage vessel was first located at the site, including the days when the storage vessel was removed, must be added to the count towards the number of consecutive days.

(5) Records of the identification and location of each storage vessel subject to emission control requirements.

(6) Except as specified in paragraph (a)(6)(vii) of this section, you must maintain the records specified in paragraphs (a)(6)(i) through (vi) of this section for each control device tested under section F(d) which meets the criteria in section F(d)(11) and meets the continuous

compliance requirements in section F(d) (e) and used to comply with section A.2(a) for each storage vessel.

(i) Make, model and serial number of purchased device.

(ii) Date of purchase.

(iii) Copy of purchase order.

(iv) Location of the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(v) Inlet gas flow rate.

(vi) Records of continuous compliance requirements in section F(e) as specified in paragraphs (a)(6)(vi)(A) through (E).

(A) Records that the pilot flame is present at all times of operation.

(B) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15 minute period.

(C) Records of the maintenance and repair log.

(D) Records of the visible emissions test following return to operation from a maintenance or repair activity.

(E) Records of the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(vii) As an alternative to the requirements of paragraph (a)(6)(iv) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the storage vessel and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital

photograph, the digital photograph may consist of a photograph of the storage vessel and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(7) Records of each closed vent system inspection required under section A.4(d)(1)(i).

(8) A record of each cover inspection required under section A.4(d)(2)(i).

(9) If you are subject to the bypass requirements of section A.4(d)(3), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(10) For each carbon adsorber installed on a storage vessel, records of the schedule for carbon replacement (as determined by the design analysis requirements of section E.1(a)(2)) and records of each carbon replacement as specified in section E.1(c)(1).

(11) For each storage vessel subject to the control device requirements of section E.2(c) and (d), records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in section E.2(h). Records of section 11, EPA Method 22, 40 CFR part 60, appendix A-7 results, which include: company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22-1 in EPA Method 22, 40 CFR part 60, appendix A-7. Control device manufacturer operating instructions, procedures and maintenance schedule must be available for inspection.

(12) A log of records as specified in sections A.2(e)(1)(i)(C) and F(e)(4), for all inspection, repair and maintenance activities for each control device failing the visible emissions test.

(b) *Reporting requirements.* For storage vessels, you must submit annual reports containing the information specified in paragraphs (b)(1) through (6) of this section.

(1) An identification, including the location, of each storage vessel subject to VOC emission control requirements. The location of the storage vessel shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(2) Documentation of the VOC emission rate determination according to section A.1(a).

(3) Records of deviations specified in paragraph (a)(3) of this section that occurred during the reporting period.

(4) A statement that you have met the requirements specified in section A.3(b) and (c).

(5) You must identify each storage vessel that is removed from service during the reporting period as specified in section A.2(j)(1), including the date the storage vessel was removed from service.

(6) You must identify each storage vessel returned to service during the reporting period as specified in section A.2(j)(3), including the date the storage vessel was returned to service.

A.6 Definitions

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding \$25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including, but not limited to, general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.*, a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Completion combustion devices include pit flares.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Hydraulic fracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

Maximum average daily throughput means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a

production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Produced water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

Qualified professional engineer means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in at least one state in which the certifying official is located.

Removed from service means that a storage vessel subject to the VOC control requirements has been physically isolated and disconnected from the process for a purpose other than maintenance.

Returned to service means that a storage vessel subject to the VOC requirements that was removed from service has been:

(1) Reconnected to the original source of liquids or has been used to replace any storage vessel subject to the VOC requirements; or

(2) Installed in any location covered by this rule and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process that is operational where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered for beneficial use.

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of section A.2(j)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this rule, the following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by section A.5(a)(4), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site.

(2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals (29.7 pounds per square inch) and without emissions to the atmosphere.

B Pneumatic Controllers: VOC Emission Control Requirements

B.1 Applicability

The VOC emission control requirements specified in section B.2 apply to the pneumatic controllers specified in paragraphs (a) and (b) of this section.

(a) For natural gas processing plants, each pneumatic controller, which is a single continuous bleed natural gas-driven pneumatic controller.

(b) At locations from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline, each pneumatic controller, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 standard cubic feet per hour.

B.2 What VOC Emission Control Requirements Apply to Pneumatic Controllers?

For each pneumatic controller, you must comply with requirements for VOC, as specified in either paragraph (b)(1) or (c)(1) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) of this section are exempt from these requirements.

(a) The requirements of paragraph (b)(1) or (c)(1) of this section are not required if you determine that the use of a pneumatic controller with a bleed rate greater than the applicable standard is required based on functional needs including, but not limited to, response time, safety and positive actuation. However, you must tag such pneumatic controller with the date that the pneumatic controller is required to comply with the model rule (as established by your regulatory authority) and identification information that allows traceability to the records for that pneumatic controller, as required in section B.5(a)(2).

(b)(1) Each pneumatic controller subject to VOC emissions control requirements at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller subject to VOC emissions control requirements at a natural gas processing plant, as defined in section B.1(a), must be tagged with the date that the pneumatic controller is required to comply with the model rule (as established by your regulatory authority) and identification information that allows traceability to the records for that pneumatic controller as required in section B.5(a)(3).

(c)(1) Each pneumatic controller subject to VOC emissions control requirements at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller subject to VOC emission control requirements at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline, as defined in section B.1(b), must be tagged with the date that the pneumatic controller is required to comply with the model rule (as established by your regulatory authority) that allows traceability to the records for that controller as required in section B.5(a).

(d) You must demonstrate initial compliance by the compliance date established by your regulatory authority by demonstrating compliance with the VOC emission reduction requirements that apply to pneumatic controllers as required by section B.3.

(e) You must demonstrate continuous compliance with VOC emission reduction requirements that apply to pneumatic controllers as required by section B.4.

(f) You must perform the required recordkeeping as required by B.5(a) and reporting as required by section B.5(b).

B.3 Initial Compliance Demonstration Requirements

You must demonstrate initial compliance with the VOC emission control requirements for your pneumatic controller by complying with the requirements specified in paragraphs (a) through (f) of this section by the compliance date established by your regulatory authority, as applicable.

(a) You must demonstrate initial compliance by maintaining records as specified in section B.5(a)(2) of your determination that the use of a pneumatic controller with a bleed rate greater than the applicable standard is required as specified in section B.2(a).

(b) You own or operate a pneumatic controller located at a natural gas processing plant and your pneumatic controller is a non-natural gas-driven pneumatic controller that emits zero natural gas and VOC.

(c) You own or operate a pneumatic controller located between the wellhead and a natural gas processing plant and the manufacturer's design specifications indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.

(d) You must tag each pneumatic controller according to the requirements of section B.2(b)(2) or (c)(2).

(e) You must include the information in paragraph (a) of this section and a listing of the pneumatic controller sources specified in paragraphs (b) and (c) of this section in the initial annual report according to the requirements of section B.5(b)

(f) You must maintain the records as specified in section B.5(a) for each pneumatic controller subject to VOC emission control requirements.

B.4 Continuous Compliance Demonstration Requirements

For each pneumatic controller, you must demonstrate continuous compliance according to paragraphs (a) through (c) of this section.

(a) You must continuously operate each pneumatic controller as required in section B.2(a), (b), or (c).

(b) You must submit the annual reports as required in section B.5(b).

(c) You must maintain records as required in section B.5(a).

B.5 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements.* For each pneumatic controller, you must maintain the records identified in paragraphs (a)(1) through (4) of this section onsite or at the nearest local field office for at least five years.

(1) Records of the date, location and manufacturer specifications for each pneumatic controller.

(2) If applicable, a record of the demonstration that the use of a pneumatic controller with a natural gas bleed rate greater than the applicable standard is required and the reasons why.

(3) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(4) Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in section B.2.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (3) of this section.

(1) An identification of each existing pneumatic controller, including the identification information specified in section B.2(b)(2) or (c)(2).

(2) If applicable, documentation that the use of a pneumatic controller with a natural gas bleed rate greater than the applicable standard is required and the reasons why.

(3) Records of deviations specified in paragraph (a)(4) of this section that occurred during the reporting period.

B.6 Definitions

Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.

Continuous bleed means a continuous flow of pneumatic supply natural gas to a pneumatic controller.

Custody transfer means the transfer of natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Natural gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Non-natural gas-driven pneumatic controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Underground storage vessel means a storage vessel stored below ground

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

C Compressors: VOC Emissions Control Requirements

C.1 Applicability

(a) *Centrifugal compressors.* Each centrifugal compressor, which is a single centrifugal compressor using wet seals located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not a source subject to VOC requirements under this rule.

(b) *Reciprocating compressors.* Each reciprocating compressor located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not a source subject to VOC requirements under this rule.

C.2 What VOC Emission Control Requirements Apply to Centrifugal Compressors?

For each centrifugal compressor, you must comply with the VOC emissions control requirements in paragraphs (a) through (g).

(a) You must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent.

(b) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of section D.1(a)(1). The cover must be connected through a closed vent system that meets the requirements of section D.1(b) and the closed vent system must be routed to a control device that meets the conditions specified in paragraph (d) of this section. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(c) For each control device used to comply with the VOC emission reduction control requirements in paragraph (a), you must install and operate a continuous parameter monitoring

system for each control device as specified in section E.2(a) through (f), except as provided for in section E.2(b).

(d) You must operate each control device installed on your centrifugal compressor in accordance with the requirements specified in paragraphs (d)(1) and (2) of this section.

(1) You must operate each control device used to comply with this rule at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system through the closed vent system to the control device. You may vent more than one source to a single control device.

(2) For each control device monitored in accordance with the requirements of section E.2(a) through (f), you must demonstrate continuous compliance according to the requirements of section C.5(a)(2), as applicable.

(e) You must demonstrate initial compliance with the VOC emission reduction requirements that apply to each centrifugal compressor as required by section C.4(a).

(f) You must demonstrate continuous compliance with the VOC emission control requirements that apply to each centrifugal compressor as required by section C.5(a).

(g) You must perform the required recordkeeping and reporting as required by section C.6(a)(1) and (b)(1), as applicable.

C.3 What VOC Emission Control Requirements Apply to Reciprocating Compressors?

You must comply with the VOC emission control requirements in paragraphs (a) through (d) of this section for each reciprocating compressor.

(a) You must replace the reciprocating compressor rod packing according to either paragraph (a)(1) or (2) of this section or you must comply with paragraph (a)(3) of this section.

(1) On or before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning on the compliance date for your

reciprocating compressor as established by your regulatory authority, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the compliance date for a reciprocating compressor for which the rod packing has not yet been replaced.

(3) Route VOC emissions to a process by using a rod packing emissions collection system that operates under negative pressure and meets the cover requirements of section D.1(a)(2) and the closed vent system requirements of section D.1.(b).

(b) You must demonstrate initial compliance with requirements that apply to reciprocating compressor sources as required by section C.4(b).

(c) You must demonstrate continuous compliance with requirements that apply to reciprocating compressor sources as required by section C.5(b).

(d) You must perform the required recordkeeping and reporting as required by section C.6(a)(2) and (b)(2).

C.4 Initial Compliance Demonstration Requirements

You must demonstrate initial compliance with the VOC emission control requirements for each centrifugal compressor by complying with the requirements in paragraph (a) of this section, and for each reciprocating compressor by complying with the requirements in paragraph (b) of this section.

(a) *Centrifugal compressors.* You have achieved initial compliance with the VOC emission control requirements for each centrifugal compressor if you have complied with paragraphs (a)(1) through (7) of this section.

(1) You reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater as required in section C.2(a) and as demonstrated by section F.

(2) You use a control device to reduce emissions, and you equip the wet seal fluid degassing system with a cover that meets the requirements of section D.1(a) that is connected through a closed vent system that meets the requirements of section D.1(b) and is routed to a control device that meets the requirements of section E.1. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(3) You conduct an initial performance test as required in section F within 180 days after the compliance date established by your regulatory authority.

(4) You conduct the initial cover and closed vent system inspections required in section D.2 within 180 days after the compliance date established by your regulatory authority.

(5) You install and operate the continuous parameter monitoring systems in accordance with section E.2(a) through (g).

(6) You submit the initial annual report for your centrifugal compressor as required in section C.6(b)(1).

(7) You maintain the records as specified in section C.6(a)(1).

(b) *Reciprocating compressors.* You have achieved initial compliance with the VOC emission control requirements for each reciprocating compressor if you have complied with paragraphs (b)(1) through (4) of this section.

(1) If complying with section C.3(a)(1) and (2), you must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement, beginning on the compliance date established by your regulatory authority.

(2) If complying with section C.3(a)(3), you must route VOC emissions to a process by using a rod packing emissions collection system that operates under negative pressure and meets the cover requirements of section D.1(a)(2) and the closed vent system requirements of section D.1(b) by the compliance date established by your regulatory authority.

(3) You must submit the initial annual report for your reciprocating compressor as required in section C.6(b)(2).

(4) You maintain the records as specified in section C.6(a)(2).

C.5 Continuous Compliance Demonstration Requirements

You have demonstrated continuous compliance for each centrifugal compressor by complying with the requirements of paragraph (a), and for each reciprocating compressor by complying with the requirements of paragraph (b).

(a) *Centrifugal compressors.* For each centrifugal compressor subject to VOC emission reduction requirements, you must demonstrate continuous compliance according to paragraphs (a)(1) through (4) of this section.

(1) You must reduce VOC emissions from the wet seal fluid degassing system by 95.0 percent or greater.

(2) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of section C.2(a) using the procedures specified in paragraphs (a)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in section C.2(a), you may demonstrate compliance according to paragraph (a)(2)(viii) of this section. You may switch between compliance with paragraphs (a)(2)(i) through (vii) of this section and compliance with paragraph (a)(2)(viii) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next annual report, following the change.

(i) You must operate below (or above) the site specific maximum (or minimum) parameter value established according to the requirements of section E.2(f)(1).

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with section E.2(e) except that the inlet gas flow rate to the control device must not be averaged.

(iii) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (a)(2)(ii) of this section is either equal to or greater than the minimum monitoring value or equal to or less than the maximum monitoring value established under paragraph (a)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in section F(d), compliance with the operating parameter limit is achieved when the criteria in section F(e) are met.

(iv) You must operate the continuous monitoring system required in section E.2(a) at all times the source is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments). A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(v) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other required data collection periods to assess the operation of the control device and associated control system.

(vi) Failure to collect required data is a deviation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments).

(vii) If you use a combustion control device to meet the requirements of section C.2(a) and you demonstrate compliance using the test procedures specified in section F(b), or you use a flare designed and operated in accordance with 40 CFR 60.18(b), you must comply with paragraphs (a)(2)(vii)(A) through (D) of this section.

(A) A pilot flame must be present at all times of operation.

(B) Devices must be operated with no visible emissions, except for periods not to exceed a total of one minute during any 15-minute period. A visible emissions test using section 11 of Method 22, 40 CFR part 60, appendix A-7, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(C) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(D) Following return to operation from maintenance or repair activity, each device must pass a Method 22, 40 CFR part 60, appendix A-7, visual observation as described in paragraph (a)(2)(vii)(B) of this section.

(viii) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in section C.2(a)(1), you must demonstrate compliance using the procedures in paragraphs (a)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to section E.2(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with section E.2(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (a)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (a)(2)(viii)(A) of this section.

(D) You must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (a)(2)(viii)(C) of this section.

(1) If you have less than 120 days of data for determining average TOC emission reduction, you must calculate the average TOC emission reduction for the first 120 days of operation. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the 120-day average TOC emission reduction is equal to or greater than 95.0 percent.

(2) After 120 days and no more than 364 days of operation, you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days of operation where you have data. You have demonstrated compliance with the overall 95.0 percent reduction requirement, if the average TOC emission reduction is equal to or greater than 95.0 percent.

(E) If you have data for 365 days or more of operation, you have demonstrated compliance with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in paragraph (a)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

(3) You must submit the annual reports required by section C.6(b)(1) and maintain the records as specified in section C.6(a)(1).

(4) If you comply with this rule by equipping the wet seal fluid degassing system and route emissions to a control device or process as required by section C.2(b), you must comply with the cover and closed vent requirements in section D.1(a) and (b).

(b) *Reciprocating compressors.* For each reciprocating compressor subject to VOC emission reduction requirements, you must demonstrate continuous compliance according to paragraphs (b)(1) through (4) of this section.

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor or track the number of months or the date of the most recent reciprocating compressor rod packing replacement.

(2) You must submit the annual reports as required in section C.6(b)(2) and maintain records as required in section C.6(a)(2).

(3) You must replace the reciprocating compressor rod packing on or before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

(4) If you comply with this rule by collecting and routing VOC emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure as required by section C.3(a)(3), you must operate the rod packing emissions collection system under negative pressure and continuously comply with the closed vent system requirements in section D.1(b).

C.6 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements.*

(1) *Centrifugal compressors.* For each centrifugal compressor, you must maintain records of the information specified in paragraphs (a)(1)(i) and (ii) of this section, and, if required to comply with section C.2(a), the records specified in paragraphs (a)(1)(iii) through (ix) of this section. These records must be maintained onsite or at the nearest local field office for at least five years.

(i) An identification of each existing centrifugal compressor using a wet seal system.

(ii) Records of deviations where the centrifugal compressor was not operated in compliance with requirements specified in section C.2. Except as specified in paragraph (a)(1)(ii)(G) of this section, you must maintain the records in paragraphs (a)(1)(ii)(A) through (F) of this section for each control device tested under section F(d) which meets the criteria in section F(d)(11) and meets continuous compliance requirements in section F(e) and used to comply with section C.2(a) for each centrifugal compressor.

(A) Make, model and serial number of purchased device.

(B) Date of purchase.

(C) Copy of purchase order.

(D) Location of the centrifugal compressor and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(E) Inlet gas flow rate.

(F) Records of continuous compliance requirements in section F(e) as specified in paragraphs (a)(1)(ii)(F)(1) through (5) of this section.

(1) Records that the pilot flame is present at all times of operation.

(2) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15 minute period.

(3) Records of the maintenance and repair log.

(4) Records of the visible emissions test following return to operation from a maintenance or repair activity.

(5) Records of the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(G) As an alternative to the requirements of paragraph (a)(1)(ii)(D) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the centrifugal compressor and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the centrifugal compressor and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(iii) Records of each closed vent system inspection required under section D.2(a) and (b).

(iv) A record of each cover inspection required under section D.2(c).

(v) If you are subject to the bypass requirements of section D.2(d), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(vi) If you are subject to the closed vent system no detectable emissions requirements of section D.2(a) and (b), a record of the monitoring in accordance with section D.2(e).

(vii) For each centrifugal compressor, records of the schedule for carbon replacement (as determined by the design analysis requirements of section F(c)(2) or (3)) and records of each carbon replacement as specified in section E.1(c)(1).

(viii) For each centrifugal compressor subject to the control device requirements of section E.1, records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

(ix) A log of records for all inspection, repair and maintenance activities for each control device failing the visible emissions test as specified in section C.5(a)(2)(vii)(C).

(2) *Reciprocating compressors.* For each reciprocating compressor VOC emissions source, you must maintain the records in paragraphs (a)(2)(i) through (iv) of this section. These records must be maintained onsite or at the nearest local field office for at least five years.

(i) Records of the cumulative number of hours of operation or number of months since the previous replacement of the reciprocating compressor rod packing. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system as specified in section C.3(a)(3).

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in section C.3.

(iv) If you comply by routing emissions from the rod packing to a process through a closed vent system under negative pressure. You must maintain the records in paragraphs (a)(2)(iv)(A) through (D) of this section.

(A) Records of each closed vent system inspection required under section D.2(a) and (b).

(B) If you are subject to the bypass requirements of section D.2(d), a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(C) If you are subject to the closed vent system no detectable emissions requirements of section D.2(a) and (b), a record of the monitoring in accordance with section D.2(e).

(D) A record of each cover inspection required under section D.2(c).

(b) *Reporting requirements.*

(1) *Centrifugal compressors.* For each centrifugal compressor, you must submit annual reports containing the information specified in paragraphs (b)(1)(i) through (iv) of this section.

(i) An identification of each existing centrifugal compressor using a wet seal system.

(ii) Records of deviations specified in paragraph (a)(1)(ii) of this section that occurred during the reporting period.

(iii) If required to comply with section C.2(a), the records specified in paragraphs (a)(1)(iii) through (viii) of this section.

(iv) If complying with C.2(a) with a control device tested under section F(d) which meets the criteria in section F(d)(11) and meets the continuous compliance requirements in section F(e), in the initial annual report, records specified in paragraphs (a)(1)(ii)(A) through (a)(1)(ii)(G) of this section for each centrifugal compressor using a wet seal system that is subject to this rule. In subsequent annual reports, records specified in paragraph (a)(1)(ii)(F) of this section along with information sufficient to link to the identifying information provided in the initial report.

(2) *Reciprocating compressors.* For each reciprocating compressor, you must submit annual reports containing the information specified in paragraphs (b)(2)(i) through (iii) of this section.

(i) The cumulative number of hours of operation or the number of months since the compliance date, or since the previous reciprocating compressor rod packing replacement, whichever is later. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) Records of deviations specified in paragraph (a)(2)(iii) of this section that occurred during the reporting period.

(iii) If required to comply with section C.3(a)(3), the records specified in paragraphs (a)(2)(i) through (iv) of this section.

C.7 Definitions

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low-pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this rule.

Collection system means any infrastructure that conveys gas or liquids from the well site to another location for treatment, storage, processing, recycling, disposal or other handling.

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a compressor station for purposes of this rule.

Custody transfer means the transfer of natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere, or other mechanism that provides the same function.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well.

D Cover and Closed Vent System Requirements

[Note: These requirements would not apply to covers and closed vent systems used on storage vessels.]

D.1 What Are My Cover and Closed Vent System Requirements?

You must meet the applicable requirements of this section for each cover and closed vent system where VOC emissions are routed to a control device or to a process.

(a) *Cover requirements.*

(1) Centrifugal compressor cover requirements.

(i) The cover and all openings on the cover shall form a continuous impermeable barrier over the entire surface area of the liquid in the wet seal fluid degassing system.

(ii) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) except during those times when it is necessary to use an opening as follows:

(A) To inspect, maintain, repair, or replace equipment; or

(B) To vent gases or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph (b) of this section to a control device or to a process.

(2) Reciprocating compressor cover requirements.

(i) The cover and all openings on the cover shall form a continuous impermeable barrier over the rod packing emissions collection system.

(ii) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) except during those times when it is necessary to use an opening as follows:

(A) To inspect, maintain, repair, or replace equipment; or

(B) To vent gases or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph (b) of this section to a process.

(b) *Closed vent system requirements.*

(1) (i) Centrifugal compressors. You must design the closed vent system to route all gases, vapors, and fumes emitted from the VOC emissions source to a control device or to a process. For centrifugal compressors, the closed vent system must route all gases, vapors, and fumes to a control device that meets the requirements specified in section E.1(a) through (c).

(ii) Reciprocating compressors. You must design the closed vent system to route all gases, vapors, and fumes emitted from the VOC emissions source to a process.

(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by section D.2(e).

(3) You must meet the requirements specified in paragraph (b)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or process.

(i) Except as provided in paragraph (b)(3)(ii) of this section, you must comply with either paragraph (b)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings as specified in section D.2(d)(1) and sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away for the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to section C.6(a)(1)(v) for centrifugal compressors, C.6(a)(2)(iv)(B) for reciprocating compressors or H.5(a)(2)(ii) for pneumatic pumps, as applicable.

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (b)(3)(i) of this section.

(4) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all emissions from the emission source are routed to the control device and that the control device is of sufficient design and capacity to accommodate all emissions from the emission source and have it certified by a qualified professional engineer in accordance with paragraphs (b)(4)(i) and (ii) of this section.

(i) You must provide the following certification, signed and dated by the qualified professional engineer: “I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted and this report was prepared pursuant to the requirements of this rule. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information.”

(ii) The assessment shall be prepared under the direction or supervision of the qualified professional engineer who signs the certification in paragraph (b)(4)(i) of this section.

D.2 What Are My Initial and Continuous Cover and Closed Vent System Inspection and Monitoring Requirements?

Except as provided in paragraphs (e)(11) and (12) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a) and (b) of this section, inspect each cover according to the procedures and schedule specified in paragraph (c) of this section, and inspect each bypass device according to the procedures of paragraph (d) of this section.

(a) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (*e.g.*, a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1) and (2) of this section.

(1) Conduct an initial inspection according to the test methods and procedures specified in paragraph (e) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, C.6(a)(2)(iv)(C) for reciprocating compressors or H.5(a)(2)(iii) for pneumatic pumps, as applicable.

(2) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (e) of this section to demonstrate that it operates with no detectable emissions following any time the component is repaired or the connection is unsealed. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, C.6(a)(2)(iv)(C) for reciprocating compressors or H.5(a)(2)(iii) for pneumatic pumps, as applicable.

(b) For closed vent system components other than those specified in paragraph (a) of this section, you must meet the requirements of paragraphs (b)(1) through (3) of this section.

(1) Conduct an initial inspection according to the test methods and procedures specified in paragraph (e) of this section to demonstrate that the closed vent system operates with no detectable emissions by the date established by your regulatory authority. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, C.6(a)(2)(iv)(C) for reciprocating compressors or H.5(a)(2)(iii) for pneumatic pumps, as applicable.

(2) Conduct annual inspections according to the test methods and procedures specified in paragraph (e) of this section to demonstrate that the components or connections operate with no detectable emissions. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, C.6(a)(2)(iv)(C) for reciprocating compressors or H.5(a)(2)(iii) for pneumatic pumps, as applicable.

(3) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose

connections; liquid leaks; or broken or missing caps or other closure devices. You must maintain records of the inspection results according to section C.6(a)(1)(vi) for centrifugal compressors, or H.5(a)(2)(i) for pneumatic pumps, as applicable.

(c) For each cover, you must meet the requirements in paragraphs (c)(1) and (2) of this section.

(1) Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices.

(2) You must initially conduct the inspections specified in paragraph (c)(1) of this section following the installation of the cover. Thereafter, you must perform the inspection at least once every calendar year, except as provided in paragraphs (e)(11) and (12) of this section. For centrifugal compressors, you must maintain records of the inspection results according to section C.6(a)(1)(iv). For reciprocating compressors, you must maintain records of the inspection results according to C.6(a)(2)(iv)(D).

(d) For each bypass device, except as provided for in section D.1(b)(3)(ii), you must meet the requirements of paragraphs (d)(1) or (2) of this section.

(1) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the stream away from the control device to the atmosphere.

(2) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections according to section C.6(a)(1)(v) for centrifugal compressors, C.6(a)(2)(iv)(B) for reciprocating compressors or H.5(a)(2)(ii) for pneumatic pumps, as applicable.

(e) *No detectable emissions test methods and procedures.* If you are required to conduct an inspection of a closed vent system or cover as specified in paragraphs (a), (b), or (c) of this section, you must meet the requirements of paragraphs (e)(1) through (13) of this section.

(1) You must conduct the no detectable emissions test procedure in accordance with Method 21, 40 CFR part 60, appendix A-7.

(2) The detection instrument must meet the performance criteria of Method 21, 40 CFR part 60, appendix A-7, except that the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) You must calibrate the detection instrument before use on each day of its use by the procedures specified in EPA Method 21, 40 CFR part 60, appendix A-7.

(4) Calibration gases must be as specified in paragraphs (e)(4)(i) and (ii) of this section.

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in EPA Method 21, 40 CFR part 60, appendix A-7.

(6) Your detection instrument must meet the performance criteria specified in paragraphs (e)(6)(i) and (ii) of this section.

(i) Except as provided in paragraph (e)(6)(ii) of this section, the detection instrument must meet the performance criteria of EPA Method 21, 40 CFR part 60, appendix A-7, except the instrument response factor criteria in section 8.1.1 of EPA Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream.

For process streams that contain nitrogen, air, or other inerts that are not volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(ii) If no instrument is available that will meet the performance criteria specified in paragraph (e)(6)(i) of this section, you may adjust the instrument readings by multiplying by the average response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (e)(6)(i) of this section.

(7) You must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (e)(7)(i) or (ii) of this section.

(i) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (e)(8) of this section.

(ii) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (e)(5) of this section with the applicable value for the potential leak interface as specified in paragraph (e)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (e)(7) of this section is less than 500 parts per million by volume.

(9) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (e)(9)(i) and (ii) of this section, except as provided in paragraph (e)(10) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 15 calendar days after the leak is detected.

(10) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(11) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (e)(11)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a) through (c) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a), (b), or (c) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(12) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (e)(12)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a) through (c) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(13) *Records.* Records shall be maintained as specified in this section and in sections that reference this section.

E VOC Emission Control Device Requirements

[These requirements do not apply to control devices used on storage vessels.]

E.1 Initial Control Device Compliance Requirements

You must meet the applicable requirements of this section for each control device used to comply with VOC emission reduction requirements.

(a) Each control device used to meet the VOC emission reduction requirements must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a control device model tested under section F(d), which meets the criteria in section F(d)(11) and the continuous compliance requirements in section F(e).

(1) Each combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section.

(i) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of section F(b), with the exceptions noted in section F(a).

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of section F(b), with the exceptions noted in section F(a).

(iii) You must operate at a minimum temperature of 760° Celsius for a control device, provided the control device has demonstrated, during the performance test conducted under section F(b), that combustion zone temperature is an indicator of destruction efficiency.

(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(2) Each vapor recovery device (e.g., carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of section F(b). As an alternative to the performance testing requirements, you may demonstrate initial compliance by conducting a design analysis for vapor recovery devices according to the requirements of section F(c).

(3) You must design and operate a flare in accordance with the requirements of 40 CFR 60.18(b), and you must conduct the compliance determination using EPA Method 22 of 40 CFR part 60, appendix A-7, to determine visible emissions.

(b) You must operate each control device installed to control VOC emissions from your emissions source in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this rule at all times when gases, vapors, and fumes are vented from your VOC emissions source through the closed vent system to the control device. You may vent more than one source to a control device used to comply with this rule.

(2) For each control device monitored in accordance with the requirements of section E.2(a) through (g), you must demonstrate continuous compliance according to the requirements of section C.5(a)(2) for centrifugal compressors, as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (c)(1) and (2) of this section.

(1) Following the compliance date established by your regulatory authority for the source using the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to section F(c)(2) or (3) or according to the design required in paragraph (a)(2) of this

section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement.

(2) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(2)(i) through (vi) of this section.

(i) Regenerate or reactivate the spent carbon in a thermal treatment unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(ii) Regenerate or reactivate the spent carbon in a unit equipped with operating organic air emission controls in accordance with an emissions standard for VOC under a subpart in 40 CFR part 60 or part 63.

(iii) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(iv) Burn the spent carbon in a hazardous waste boiler or industrial furnace for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(v) Burn the spent carbon in an industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(vi) Burn the spent carbon in an industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

E.2 Continuous Control Device Monitoring Requirements

You must meet the applicable requirements of this section to demonstrate continuous compliance for each control device used to meet VOC emission control requirements.

(a) For each control device used to comply with the VOC emission reduction requirements, you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with section E.1(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section.

(b) You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel, or used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) If you are required to install a continuous parameter monitoring system, you must meet the specifications and requirements in paragraphs (c)(1) through (4) of this section.

(1) Each continuous parameter monitoring system must measure data values at least once every hour and record the parameters in paragraphs (c)(1)(i) or (ii) of this section.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(2) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your approved site-specific monitoring plan. Heat sensing monitoring devices that indicate the

continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements in this section.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in 40 CFR 60.13(b).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in 40 CFR 60.7(c), (d), and (f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in accordance with the site-specific monitoring plan. Heat sensing monitoring devices that indicate the continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements in this section.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in either paragraph (d)(1), (2), or (3) of this section.

(1) A continuous monitoring system that measures the operating parameters in paragraphs (d)(1)(i) through (viii) of this section, as applicable.

(i) For a thermal vapor incinerator that demonstrates during the performance test conducted under section F(b) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in °Celsius, or $\pm 2.5^\circ\text{Celsius}$, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(ii) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ± 1 percent of the temperature being monitored in °Celsius, or $\pm 2.5^\circ\text{Celsius}$, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame. The heat sensing monitoring device is exempt from the calibration requirements of this section.

(iv) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in °Celsius, or $\pm 2.5^\circ\text{Celsius}$, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(v) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in °Celsius, or $\pm 2.5^\circ\text{Celsius}$, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(vi) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(1)(vi)(A) and (B) of this section.

(A) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(B) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{Celsius}$, or $\pm 2.5^{\circ}\text{Celsius}$, whichever value is greater.

(vii) For a non-regenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a design analysis performed as specified in section F(c)(3). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(viii) For a combustion control device whose model is tested under section F(d), a continuous monitoring system meeting the requirements of paragraphs (d)(1)(viii)(A) and (B) of this section. If you comply with the periodic testing requirements of F(b)(5)(ii), you are not required to continuously monitor the gas flow rate under paragraph (d)(1)(viii)(A).

(A) The continuous monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ± 2 percent or better at the maximum expected flow rate. The flow rate at the inlet to the combustion device must not exceed the maximum or minimum flow rate determined by the manufacturer.

(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the control device.

(2) An organic monitoring device equipped with a continuous recorder that measures the concentration level of organic compounds in the exhaust vent stream from the control device. The monitor must meet the requirements of Performance Specification 8 or 9 of 40 CFR part 60, appendix B. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications.

(e) You must calculate the daily average value for each monitored operating parameter for each operating day, using the data recorded by the monitoring system, except for inlet gas flow rate and data from the heat sensing devices that indicate the presence of a pilot flame. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of section E.1(a)(1) or (2). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) If you conduct performance tests in accordance with the requirements of section F(b) to demonstrate that the control device achieves the applicable performance requirements specified in section E.1(a)(1) or (2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(ii) If you use a condenser design analysis in accordance with the requirements of section F(c) to demonstrate that the control device achieves the applicable performance requirements specified in section E.1(a)(2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on the condenser design analysis and supplemented, as necessary, by the condenser manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under section F(d) to demonstrate that the control device achieves the applicable performance requirements specified in section E.1(a)(1), then your control device inlet gas flow rate must not exceed the maximum or minimum inlet gas flow rate determined by the manufacturer.

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of section F(b) to demonstrate that the condenser achieves the applicable performance requirements in section E.1(a)(2), then the condenser performance curve must be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(ii) If you use a control device design analysis in accordance with the requirements of section F(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in section E.1(a)(2), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (6) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (6) of this

section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section or when the heat sensing device indicates that there is no pilot flame present.

(2) If you meet section E.1(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in section C.5(a)(2)(viii)(D) is less than 95.0 percent.

(3) If you meet section E.1(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in section C.5(a)(2)(viii)(D)(1) or (2) is less than 95.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraphs (g)(5)(i) or (ii) of this section are met.

(i) For each bypass line subject to section D.1(b)(3)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to section D.1(b)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under section F(d), a deviation occurs when the conditions of paragraphs (g)(6)(i) or (ii) are met.

(i) The inlet gas flow rate exceeds the maximum established during the test conducted under section F(d).

(ii) Failure of the monthly visible emissions test conducted under section F(e)(3) occurs.

F Performance Test Procedures

This section applies to the performance testing of control devices used to demonstrate compliance with your VOC emission control requirements. You must demonstrate that a control device achieves the performance requirements specified for your centrifugal compressor using the performance test methods and procedures specified in this section. For condensers and carbon adsorbers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section. In addition, this section contains the requirements for enclosed combustion device performance tests conducted by the manufacturer, as relevant and allowed for compliance demonstration purposes.

(a) *Performance test exemptions.* You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.

(1) *A flare that is designed and operated in accordance with 40 CFR 60.18(b).* You must conduct the compliance determination using EPA Method 22, 40 CFR part 60, appendix A-7, to determine visible emissions.

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have either been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H; you have submitted a Notification of Compliance under 40 CFR 63.1207(j) and comply with the requirements of 40 CFR part 63, subpart EEE; or you comply with 40 CFR part 63, subpart EEE and will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in the rule for submitting the initial performance test report.

(5) A hazardous waste incinerator for which you have submitted a Notification of Compliance under 40 CFR 63.1207(j), or for which you will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in the rule for submitting the initial performance test report, and you comply with the requirements of 40 CFR part 63, subpart EEE.

(6) A performance test is waived in accordance with 40 CFR 60.8(b).

(7) A control device whose model can be demonstrated to meet the performance requirements of section E.1(a) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) *Test methods and procedures.* You must use the test methods and procedures specified in paragraphs (b)(1) through (5) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of section E.1(a) or A.2(e)(1). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) of this section. Each performance test must consist of a minimum of 3 test runs. Each run must be at least 1 hour long.

(1) You must use EPA Method 1 or 1A, 40 CFR part 60, appendix A-1, as appropriate, to select the sampling sites specified in paragraphs (b)(1)(i) and (ii) of this section. Any references to particulate mentioned in EPA Methods 1 and 1A do not apply to this section.

(i) Sampling sites must be located at the inlet of the first control device and at the outlet of the final control device, to determine compliance with the control device percent reduction requirement.

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with the enclosed combustion device TOC exhaust gas concentration limit.

(2) You must determine the gas volumetric flowrate using EPA Method 2, 2A, 2C, or 2D, 40 CFR part 60, appendix A-2, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in section E.1(a)(1)(i) or (a)(2), or section A.2(e)(1)(i)(D)(1) or (e)(1)(ii), you must

use EPA Method 25A at 40 CFR part 60, appendix A-7. You must use EPA Method 4 at 40 CFR part 60, appendix A-3 to convert the EPA Method 25A results to a dry basis. You must use the procedures in paragraphs (b)(3)(i) through (iii) of this section to calculate percent reduction efficiency.

(i) You must compute the mass rate of TOC using the following equations:

$$E_i = K_2 C_i M_p Q_i$$

$$E_o = K_2 C_o M_p Q_o$$

Where:

E_i , E_o = Mass rate of TOC at the inlet and outlet of the control device, respectively, dry basis, kilograms per hour.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20°Celsius.

C_i , C_o = Concentration of TOC, as propane, of the gas stream as measured by EPA Method 25A at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M_p = Molecular weight of propane, 44.1 gram/gram-mole.

Q_i , Q_o = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

(ii) You must calculate the percent reduction in TOC as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} * 100\%$$

Where:

R_{cd} = Control efficiency of control device, percent.

E_i = Mass rate of TOC at the inlet to the control device as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

E_o = Mass rate of TOC at the outlet of the control device, as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

(iii) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC across the device by comparing the TOC in all combusted vent streams and primary and secondary fuels with the TOC exiting the device, respectively.

(4) You must use EPA Method 25A, 40 CFR part 60, appendix A-7 to measure TOC, as propane, to determine compliance with the TOC exhaust gas concentration limit specified in section E.1(a)(1)(ii) or section A.2(e)(1)(i)(D)(2). You may also use EPA Method 18, 40 CFR part 60, appendix A-6 to measure methane and ethane. You may subtract the measured concentration of methane and ethane from the EPA Method 25A measurement to demonstrate compliance with the concentration limit. You must determine the concentration in parts per million by volume on a wet basis and correct it to 3 percent oxygen, using the procedures in paragraphs (b)(4)(i) through (iii) of this section.

(i) If you use EPA Method 18 to determine methane and ethane, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run. You must determine the average methane and ethane concentration per run. The samples must be taken during the same time as the EPA Method 25A sample.

(ii) You may subtract the concentration of methane and ethane from the EPA Method 25A TOC, as propane, concentration for each run.

(iii) You must correct the TOC concentration (minus methane and ethane, if applicable) to 3 percent oxygen as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of EPA Method 3A or 3B, 40 CFR 60, appendix A-2, ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration.

(B) You must correct the TOC concentration for percent oxygen as follows:

$$C_c = C_m \left(\frac{17.9}{20.9 - \%O_{2m}} \right)$$

Where:

C_c = TOC concentration, as propane, corrected to 3 percent oxygen, parts per million by volume on a wet basis.

C_m = TOC concentration, as propane, (minus methane and ethane, if applicable), parts per million by volume on a wet basis.

$\%O_{2m}$ = Concentration of oxygen, percent by volume as measured, wet.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after the compliance date for your source as established by your regulatory authority.

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests except as specified in paragraphs (b)(5)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct

subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit.

(A) A control device whose model is tested under, and meets the criteria of paragraph (d) of this section. For centrifugal compressors, if you do not continuously monitor the gas flow rate in accordance with section E.2(d)(1)(viii), then you must comply with the periodic performance testing requirements of paragraph (b)(5)(ii).

(B) A combustion control device tested under paragraph (b) of this section that meets the outlet TOC performance level specified in section E.1(a)(1)(ii) and that establishes a correlation between firebox or combustion chamber temperature and the TOC performance level. For centrifugal compressors, you must establish a limit on temperature in accordance with section E.2(f) and continuously monitor the temperature as required by section E.2(d).

(c) *Control device design analysis to meet the requirements of section E.1(a).* (1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and must establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream and the design average temperatures of the coolant fluid at the condenser inlet and outlet.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon

used for the carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems will incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the regulatory authority do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the requirements of paragraph (b) of this section to resolve the disagreement. The regulatory authority may choose to have an authorized representative observe the performance test.

(d) Performance testing for combustion control devices—manufacturers' performance test. (1) This paragraph applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer must demonstrate that a specific model of control device achieves the performance requirements in paragraph (d)(11) of this section by conducting a performance test as specified in paragraphs (d)(2) through (10) of this section. You must submit a test report for each combustion control device in accordance with the requirements in paragraph (d)(12) of this section.

(2) Performance testing must consist of three one-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. Propene (propylene) gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90-100 percent of maximum design rate (fixed rate).

(ii) 70-100-70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30-70-30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent

of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0-30-0 percent (ramp up, ramp down). Begin the test at the minimum firing rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to the minimum firing rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures must be tested simultaneously and with all burners operational. Results must be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System. A graphic presentation or strip chart of the control device operating data and emissions test data must be included in the test report in accordance with paragraph (d)(12) of this section. Inlet fuel meter data may be manually recorded provided that all inlet fuel data readings are included in the final report.

(4) Inlet testing must be conducted as specified in paragraphs (d)(4)(i) and (ii) of this section.

(i) The inlet gas flow metering system must be located in accordance with EPA Method 2A, 40 CFR part 60, appendix A-1 (or other approved procedure) to measure inlet gas flow rate at the control device inlet location. You must position the fitting for filling fuel sample containers a minimum of eight pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet flow rate must be determined using EPA Method 2A, 40 CFR part 60, appendix A-1. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute test.

(5) Inlet gas sampling must be conducted as specified in paragraphs (d)(5)(i) and (ii) of this section.

(i) At the inlet gas sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3-hour period. Filling must be conducted as specified in paragraphs (d)(5)(i)(A) through (C) of this section.

(A) Open the canister sampling valve at the beginning of each test run, and close the canister at the end of each test run.

(B) Fill one canister across the three test runs such that one composite fuel sample exists for each test condition.

(C) Label the canisters individually and record sample information on a chain of custody form.

(ii) Analyze each inlet gas sample using the methods in paragraphs (d)(5)(ii)(A) through (C) of this section. You must include the results in the test report required by paragraph (d)(12) of this section.

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945-03.

(B) Hydrogen (H₂), carbon monoxide (CO), carbon dioxide (CO₂), nitrogen (N₂), oxygen (O₂) using ASTM D1945-03.

(C) Higher heating value using ASTM D3588-98 or ASTM D4891-89.

(6) Outlet testing must be conducted in accordance with the criteria in paragraphs (d)(6)(i) through (v) of this section.

(i) Sample and flow rate must be measured in accordance with paragraphs (d)(6)(i)(A) and (B) of this section.

(A) The outlet sampling location must be a minimum of four equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one

equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports must be used.

(B) Flow rate must be measured using EPA Method 1, 40 CFR part 60, appendix A-1 for determining flow measurement traverse point location, and EPA Method 2, 40 CFR part 60, appendix A-1 for measuring duct velocity. If low flow conditions are encountered (*i.e.*, velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer must be used to obtain an accurate flow profile.

(ii) Molecular weight and excess air must be determined as specified in paragraph (d)(7) of this section.

(iii) Carbon monoxide must be determined as specified in paragraph (d)(8) of this section.

(iv) THC must be determined as specified in paragraph (d)(9) of this section.

(v) Visible emissions must be determined as specified in paragraph (d)(10) of this section.

(7) Molecular weight and excess air determination must be performed as specified in paragraphs (d)(7)(i) through (iii) of this section.

(i) An integrated bag sample must be collected during the moisture test required by EPA Method 4, 40 CFR part 60, appendix A-3 following the procedure specified in paragraphs (d)(7)(i)(A) and (B) of this section. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC-TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(C) and (D) of this section.

(A) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(B) Purge the sampling line with stack gas before opening the valve and beginning to fill the bag. Clearly label each bag and record sample information on a chain of custody form.

(C) The bag contents must be vigorously mixed prior to the gas chromatograph analysis.

(D) The GC-TCD calibration procedure in EPA Method 3C, 40 CFR part 60, appendix A-2, must be modified by using EPA Alt-045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, repeat the initial calibration using at least three concentration levels.

(ii) Calculate and report the molecular weight of oxygen, carbon dioxide, methane, and nitrogen in the integrated bag sample and include in the test report specified in paragraph (d)(12) of this section. Moisture must be determined using EPA Method 4, 40 CFR part 60, appendix A-3. Traverse both ports with the EPA Method 4, 40 CFR part 60, appendix A-3, sampling train during each test run. Ambient air must not be introduced into the integrated bag sample required by EPA Method 3C, 40 CFR part 60, appendix A-2, sample during the port change.

(iii) Excess air must be determined using resultant data from the EPA Method 3C tests and EPA Method 3B, 40 CFR part 60, appendix A-2, equation 3B-1, or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only).

(8) Carbon monoxide must be determined using EPA Method 10, 40 CFR part 60, appendix A-4. Run the test simultaneously with EPA Method 25A, 40 CFR part 60, appendix A-7 using the same sampling points. An instrument range of 0-10 parts per million by volume-dry (ppmvd) is recommended.

(9) Total hydrocarbon determination must be performed as specified in paragraphs (d)(9)(i) through (vii) of this section.

(i) Conduct THC sampling using EPA Method 25A, 40 CFR part 60, appendix A-7, except that the option for locating the probe in the center 10 percent of the stack is not allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during each test run.

(ii) A valid test must consist of three EPA Method 25A, 40 CFR part 60, appendix A-7, tests, each no less than 60 minutes in duration.

(iii) A 0-10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0-30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases must be propane in air and be certified through EPA Protocol 1—“EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards”.

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent CO₂, as measured by EPA Method 3C, 40 CFR part 60, appendix A-2. You must use the following equation for this diluent concentration correction:

$$C_{corr} = C_{meas} \left(\frac{3}{CO_{2meas}} \right)$$

Where:

C_{meas} = The measured concentration of the pollutant.

CO_{2meas} = The measured concentration of the CO₂ diluent.

3 = The corrected reference concentration of CO₂ diluent.

C_{corr} = The corrected concentration of the pollutant.

(vii) Subtraction of methane or ethane from the THC data is not allowed in determining results.

(10) Visible emissions must be determined using EPA Method 22, 40 CFR part 60, appendix A-7. The test must be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date

and time, must be taken once per test run and the 12 photos included in the test report specified in paragraph (d)(12) of this section.

(11) *Performance test criteria.* (i) The control device model tested must meet the criteria in paragraphs (d)(11)(i)(A) through (D) of this section. These criteria must be reported in the test report required by paragraph (d)(12) of this section.

(A) Results from EPA Method 22, 40 CFR part 60, appendix A-7, results under paragraph (d)(10) of this section with no indication of visible emissions.

(B) Average EPA Method 25A, 40 CFR part 60, appendix A-7, results under paragraph (d)(9) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO₂.

(C) Average CO emissions determined under paragraph (d)(8) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO₂.

(D) Excess combustion air determined under paragraph (d)(7) of this section equal to or greater than 150 percent.

(ii) The manufacturer must determine a maximum inlet gas flow rate which must not be exceeded for each control device model to achieve the criteria in paragraph (d)(11)(iii) of this section. The maximum inlet gas flow rate must be included in the test report required by paragraph (d)(12) of this section.

(iii) A manufacturer must demonstrate a destruction efficiency of at least 95.0 percent for THC, as propane. A control device model that demonstrates a destruction efficiency of 95.0 percent for THC, as propane, will meet the control requirement for 95.0 percent destruction of VOC required under this rule.

(12) The owner or operator of a combustion control device model tested under this paragraph must submit the information listed in paragraphs (d)(12)(i) through (vi) in the test report. Owners or operators who claim that any of the performance test information being submitted is confidential business information (CBI) must submit a complete file including

information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to Attn: CBI Officer; OAQPS CBIO Room 521; 109 T.W. Alexander Drive; RTP, NC 27711. The same file with the CBI omitted must be submitted to Oil_and_Gas_PT@EPA.GOV.

- (i) A full schematic of the control device and dimensions of the device components.
- (ii) The maximum net heating value of the device.
- (iii) The test fuel gas flow range (in both mass and volume). Include the maximum allowable inlet gas flow rate.
- (iv) The air/stream injection/assist ranges, if used.
- (v) The test conditions listed in paragraphs (d)(12)(v)(A) through (O) of this section, as applicable for the tested model.
 - (A) Fuel gas delivery pressure and temperature.
 - (B) Fuel gas moisture range.
 - (C) Purge gas usage range.
 - (D) Condensate (liquid fuel) separation range.
 - (E) Combustion zone temperature range. This is required for all devices that measure this parameter.
 - (F) Excess air range.
 - (G) Flame arrestor(s).
 - (H) Burner manifold.
 - (I) Pilot flame indicator.

(J) Pilot flame design fuel and calculated or measured fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, strip charts, or other graphic presentations of the data annotated with test times and calibration values.

(e) *Continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section.* This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (d) of this section. Owners or operators must demonstrate that a control device achieves the performance requirements in (d)(11) of this section by installing a device tested under paragraph (d) of this section, complying with the criteria specified in paragraphs (e)(1) through (8) of this section and maintaining the records specified in A.5(a)(6) or E.2(a)(1)(ii).

(1) The inlet gas flow rate must be equal to or less than the maximum specified by the manufacturer.

(2) A pilot flame must be present at all times of operation.

(3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22, 40 CFR part 60, appendix A-7, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(4) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(5) Following return to operation from maintenance or repair activity, each device must pass an EPA Method 22, 40 CFR part 60, appendix A-7, visual observation as described in paragraph (e)(3) of this section.

(6) If the owner or operator operates a combustion control device model tested under this section, an electronic copy of the performance test results required by this section shall be submitted via email to Oil_and_Gas_PT@EPA.GOV unless the test results for that model of combustion control device are posted at the following Web site: epa.gov/airquality/oilandgas/.

(7) Ensure that each enclosed combustion control device is maintained in a leak free condition.

(8) Operate each control device following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

G Equipment VOC Leaks at Natural Gas Processing Plants

G.1 Applicability

(a) The group of all equipment, except compressors and sampling connection systems, within a process unit located at an onshore natural gas processing plant.

(b) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit is covered by the requirements of section G.2 if it is located at an onshore natural gas processing plant. Equipment not located at the onshore natural gas processing plant site is exempt from the requirements of section G.2.

(c) The equipment within a process unit subject to VOC emission control requirements located at onshore natural gas processing plants is exempt from this section if they are subject to and controlled according to subparts VVa or GGGa of 40 CFR part 60.

G.2 What VOC Emission Requirements Apply to Equipment at a Natural Gas Processing Plant?

(a) You must comply with the requirements of sections G.5.1 through G.5.9, except as provided in section G.3.

(b) You may elect to comply with the requirements of sections G.6.1 and G.6.2, as an alternative.

(c) You must comply with the provisions of sections G.7 and G.8 of this section, except as provided in section G.3.

G.3 What Exceptions Apply to the Equipment Leak VOC Emission Control Requirements for Equipment at Natural Gas Processing Plants?

(a) You may comply with the following exceptions to the provisions of section G.2.

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in section G.7(b) except as provided in paragraph (b)(4) of this section, and section G.5.2 of this rule.

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in section G.5.7.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a non-fractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within 5 days as specified in paragraph (b)(1) of this section and section G.5.2(b)(1).

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section must be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service that are located at a non-fractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of sections G.5.3(a)(1), G.5.5(a), G.5.9(a), and paragraph (b)(1) of this section.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of sections G.5.3(a)(1), G.5.5(a), G.5.9(a), and paragraph (b)(1) of this section.

(e) An owner or operator may use the following provisions instead of section G.7(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150°C (302°F) as determined by ASTM Method D86-96.

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150°C (302°F) as determined by ASTM Method D86-96.

G.4 How Do I Demonstrate Initial and Continued Compliance with the VOC Emission Control Requirements for Equipment at Natural Gas Processing Plants?

For equipment subject to VOC emission control requirements at natural gas processing plants, initial and continuous compliance with the VOC requirements is demonstrated if you are in compliance with the requirements of sections G.5.1 through G.5.9, except as provided in section G.3; G.6, as an alternative; and G.7 and G.8, except as provided in section G.3

G.5 What VOC Emission Control Requirements Apply to Equipment at Natural Gas Processing Plants

G.5.1 VOC Emission Control Requirements: General

(a) Each owner or operator subject to the provisions of this rule shall demonstrate compliance with the requirements of sections G.5.2 through G.5.8 for all equipment within 180 days and for G.5.9 within 12 months of the compliance date established by your regulatory authority.

(b) Compliance with sections G.5.2 to G.5.9 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in G.7.

G.5.2 What Equipment VOC Emission Control Requirements Apply to Pressure Relief Devices in Gas/Vapor Service?

(a) Except during pressure releases, each pressure relief device in gas/vapor service shall be operated with no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as determined by the methods specified in section G.7(c).

(b)(1) After each pressure release, the pressure relief device shall be returned to a condition of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, as soon as practicable, but no later than 5 calendar days after the pressure release, except as provided in section G.5.7.

(2) No later than 5 calendar days after the pressure release, the pressure relief device shall be monitored to confirm the conditions of no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, by the methods specified in section G.7(c).

(c) Any pressure relief device that is routed to a process or fuel gas system or equipped with a closed vent system capable of capturing and transporting leakage through the pressure relief device to a control device as described in section G.5.8 is exempted from the requirements of paragraphs (a) and (b) of this section.

(d)(1) Any pressure relief device that is equipped with a rupture disk upstream of the pressure relief device is exempt from the requirements of paragraphs (a) and (b) of this section, provided the owner or operator complies with the requirements in paragraph (d)(2) of this section.

(2) After each pressure release, a new rupture disk shall be installed upstream of the pressure relief device as soon as practicable, but no later than 5 calendar days after each pressure release, except as provided in section G.5.7.

G.5.3 What Equipment VOC Emission Control Requirements Apply to Pumps in Light Liquid Service?

(a)(1) Each pump in light liquid service shall be monitored monthly to detect leaks by the methods specified in G.7(b), except as provided in paragraphs (d), (e), and (f) of this section. A pump that begins operation in light liquid service after the initial startup date for the process unit must be monitored for the first time within 30 days after the end of its startup period, except for a pump that replaces a leaking pump and except as provided in paragraphs (d), (e), and (f) of this section.

(2) Each pump in light liquid service shall be checked by visual inspection each calendar week for indications of liquids dripping from the pump seal.

(b)(1) The instrument reading that defines a leak is specified in paragraphs (b)(1)(i) and (ii) of this section.

(i) 5,000 parts per million (ppm) or greater for pumps handling polymerizing monomers;

(ii) 2,000 ppm or greater for all other pumps.

(2) If there are indications of liquids dripping from the pump seal, the owner or operator shall follow the procedure specified in either paragraph (b)(2)(i) or (ii) of this section. This requirement does not apply to a pump that was monitored after a previous weekly inspection and the instrument reading was less than the concentration specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable.

(i) Monitor the pump within 5 days as specified in G.7(b). A leak is detected if the instrument reading measured during monitoring indicates a leak as specified in paragraph (b)(1)(i) or (ii) of this section, whichever is applicable. The leak shall be repaired using the procedures in paragraph (c) of this section.

(ii) Designate the visual indications of liquids dripping as a leak, and repair the leak using either the procedures in paragraph (c) of this section or by eliminating the visual indications of liquids dripping.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in G.5.7.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected. First attempts at repair include, but are not limited to, the practices described in paragraphs (c)(2)(i) and (ii) of this section, where practicable.

(i) Tightening the packing gland nuts;

(ii) Ensuring that the seal flush is operating at design pressure and temperature.

(d) Each pump equipped with a dual mechanical seal system that includes a barrier fluid system is exempt from the requirements of paragraph (a) of this section, provided the requirements specified in paragraphs (d)(1) through (6) of this section are met.

(1) Each dual mechanical seal system is:

(i) Operated with the barrier fluid at a pressure that is at all times greater than the pump stuffing box pressure; or

(ii) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed vent system to a control device that complies with the requirements of G.5.8; or

(iii) Equipped with a system that purges the barrier fluid into a process stream with zero VOC emissions to the atmosphere.

(2) The barrier fluid system is in heavy liquid service or is not in VOC service.

(3) Each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both.

(4)(i) Each pump is checked by visual inspection, each calendar week, for indications of liquids dripping from the pump seals.

(ii) If there are indications of liquids dripping from the pump seal at the time of the weekly inspection, the owner or operator shall follow the procedure specified in either paragraph (d)(4)(ii)(A) or (B) of this section prior to the next required inspection.

(A) Monitor the pump within 5 days as specified in G.7(b) to determine if there is a leak of VOC in the barrier fluid. If an instrument reading of 2,000 ppm or greater is measured, a leak is detected.

(B) Designate the visual indications of liquids dripping as a leak.

(5)(i) Each sensor as described in paragraph (d)(3) is checked daily or is equipped with an audible alarm.

(ii) The owner or operator determines, based on design considerations and operating experience, a criterion that indicates failure of the seal system, the barrier fluid system, or both.

(iii) If the sensor indicates failure of the seal system, the barrier fluid system, or both, based on the criterion established in paragraph (d)(5)(ii) of this section, a leak is detected.

(6)(i) When a leak is detected pursuant to paragraph (d)(4)(ii)(A) of this section, it shall be repaired as specified in paragraph (c) of this section.

(ii) A leak detected pursuant to paragraph (d)(5)(iii) of this section shall be repaired within 15 days of detection by eliminating the conditions that activated the sensor.

(iii) A designated leak pursuant to paragraph (d)(4)(ii)(B) of this section shall be repaired within 15 days of detection by eliminating visual indications of liquids dripping.

(e) Any pump that is designated, as described in G.8(a)(5)(ii), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraphs (a), (c), and (d) of this section if the pump:

(1) Has no externally actuated shaft penetrating the pump housing;

(2) Is demonstrated to be operating with no detectable emissions as indicated by an instrument reading of less than 500 ppm above background as measured by the methods specified in G.7(c); and

(3) Is tested for compliance with paragraph (e)(2) of this section initially upon designation, annually, and at other times requested by the Administrator.

(f) If any pump is equipped with a closed vent system capable of capturing and transporting any leakage from the seal or seals to a process or to a fuel gas system or to a control device that complies with the requirements of G.5.8, it is exempt from paragraphs (a) through (e) of this section.

(g) Any pump that is designated, as described in G.8(a)(6)(i), as an unsafe-to-monitor pump is exempt from the monitoring and inspection requirements of paragraphs (a) and (d)(4) through (6) of this section if:

(1) The owner or operator of the pump demonstrates that the pump is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section; and

(2) The owner or operator of the pump has a written plan that requires monitoring of the pump as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (c) of this section if a leak is detected.

(h) Any pump that is located within the boundary of an unmanned plant site is exempt from the weekly visual inspection requirement of paragraphs (a)(2) and (d)(4) of this section, and the daily requirements of paragraph (d)(5) of this section, provided that each pump is visually inspected as often as practicable and at least monthly.

G.5.4 What Equipment VOC Emission Control Requirements Apply to Open-Ended Valves or Lines?

(a)(1) Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve, except as provided in paragraphs (d) and (e) of this section.

(2) The cap, blind flange, plug, or second valve shall seal the open end at all times except during operations requiring process fluid flow through the open-ended valve or line.

(b) Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.

(c) When a double block-and-bleed system is being used, the bleed valve or line may remain open during operations that require venting the line between the block valves but shall comply with paragraph (a) of this section at all other times.

(d) Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirements of paragraphs (a) through (c) of this section.

(e) Open-ended valves or lines containing materials which would auto-catalytically polymerize or would present an explosion, serious overpressure, or other safety hazard if capped or equipped with a double block and bleed system as specified in paragraphs (a) through (c) of this section are exempt from the requirements of paragraphs (a) through (c) of this section.

G.5.5 What Equipment VOC Emission Control Requirements Apply to Valves in Gas/Vapor Service and in Light Liquid Service?

(a)(1) Each valve shall be monitored monthly to detect leaks by the methods specified in G.7(b) and shall comply with paragraphs (b) through (e) of this section, except as provided in paragraphs (f), (g), and (h) of this section and sections G.6.1 and G.6.2.

(2) A valve that begins operation in gas/vapor service or light liquid service after the compliance date for the process unit must be monitored according to paragraphs (a)(2)(i) or (ii),

except for a valve that replaces a leaking valve and except as provided in paragraphs (f), (g), and (h) of this section and sections G.6.1 and G.6.2.

(i) Monitor the valve as in paragraph (a)(1) of this section. The valve must be monitored for the first time within 30 days after the end of its startup period to ensure proper installation.

(ii) If the existing valves in the process unit are monitored in accordance with section G.6.1 or section G.6.2, count the new valve as leaking when calculating the percentage of valves leaking as described in section G.6.2(b)(5). If less than 2.0 percent of the valves are leaking for that process unit, the valve must be monitored for the first time during the next scheduled monitoring event for existing valves in the process unit or within 90 days, whichever comes first.

(b) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(c)(1)(i) Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected.

(ii) As an alternative to monitoring all of the valves in the first month of a quarter, an owner or operator may elect to subdivide the process unit into two or three subgroups of valves and monitor each subgroup in a different month during the quarter, provided each subgroup is monitored every 3 months. The owner or operator must keep records of the valves assigned to each subgroup.

(2) If a leak is detected, the valve shall be monitored monthly until a leak is not detected for 2 successive months.

(d)(1) When a leak is detected, it shall be repaired as soon as practicable, but no later than 15 calendar days after the leak is detected, except as provided in section G.5.7.

(2) A first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(e) First attempts at repair include, but are not limited to, the following best practices where practicable:

- (1) Tightening of bonnet bolts;
- (2) Replacement of bonnet bolts;
- (3) Tightening of packing gland nuts;
- (4) Injection of lubricant into lubricated packing.

(f) Any valve that is designated, as described in section G.8(a)(5)(ii), for no detectable emissions, as indicated by an instrument reading of less than 500 ppm above background, is exempt from the requirements of paragraph (a) of this section if the valve:

- (1) Has no external actuating mechanism in contact with the process fluid,
- (2) Is operated with emissions less than 500 ppm above background as determined by the method specified in section G.7(c), and
- (3) Is tested for compliance with paragraph (f)(2) of this section initially upon designation, annually, and at other times requested by the permitting authority.

(g) Any valve that is designated, as described in section G.8(a)(6)(i), as an unsafe-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

- (1) The owner or operator of the valve demonstrates that the valve is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraph (a) of this section, and
- (2) The owner or operator of the valve adheres to a written plan that requires monitoring of the valve as frequently as practicable during safe-to-monitor times.

(h) Any valve that is designated, as described in section G.8(a)(6)(ii), as a difficult-to-monitor valve is exempt from the requirements of paragraph (a) of this section if:

(1) The owner or operator of the valve demonstrates that the valve cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) The process unit within which the valve is located either has less than 3.0 percent of its total number of valves designated as difficult-to-monitor by the owner or operator.

(3) The owner or operator of the valve follows a written plan that requires monitoring of the valve at least once per calendar year.

G.5.6 What Equipment VOC Emission Control Requirements Apply to Pumps, Valves, and Connectors in Heavy Liquid Service and Pressure Relief Devices in Light Liquid or Heavy Liquid Service?

(a) If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method at pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, the owner or operator shall follow either one of the following procedures:

(1) The owner or operator shall monitor the equipment within 5 days by the method specified in section G.7(b) and shall comply with the requirements of paragraphs (b) through (d) of this section.

(2) The owner or operator shall eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 calendar days of detection.

(b) If an instrument reading of 10,000 ppm or greater is measured, a leak is detected.

(c)(1) When a leak is detected, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as provided in section G.5.7.

(2) The first attempt at repair shall be made no later than 5 calendar days after each leak is detected.

(d) First attempts at repair include, but are not limited to, the best practices described under sections G.5.3(c)(2) and G.5.5(e).

G.5.7 What Delay of Repair of Equipment Requirements Apply When Equipment Component Leaks Have Been Detected?

(a) Delay of repair of equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown. Monitoring to verify repair must occur within 15 days after startup of the process unit.

(b) Delay of repair of equipment will be allowed for equipment which is isolated from the process and which does not remain in VOC service.

(c) Delay of repair for valves and connectors will be allowed if:

(1) The owner or operator demonstrates that emissions of purged material resulting from immediate repair are greater than the fugitive emissions likely to result from delay of repair, and

(2) When repair procedures are effected, the purged material is collected and destroyed or recovered in a control device complying with section G.5.8.

(d) Delay of repair for pumps will be allowed if:

(1) Repair requires the use of a dual mechanical seal system that includes a barrier fluid system, and

(2) Repair is completed as soon as practicable, but not later than 6 months after the leak was detected.

(e) Delay of repair beyond a process unit shutdown will be allowed for a valve, if valve assembly replacement is necessary during the process unit shutdown, valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted. Delay of repair beyond the next process unit shutdown will not be

allowed unless the next process unit shutdown occurs sooner than 6 months after the first process unit shutdown.

(f) When delay of repair is allowed for a leaking pump, valve, or connector that remains in service, the pump, valve, or connector may be considered to be repaired and no longer subject to delay of repair requirements if two consecutive monthly monitoring instrument readings are below the leak definition.

G.5.8 What VOC Emission Control Requirements Apply for Closed Vent Systems and Control Devices?

(a) Owners or operators of closed vent systems and control devices used to comply with provisions of this rule shall comply with the provisions of this section.

(b) Vapor recovery systems (for example, condensers and absorbers) shall be designed and operated to recover the VOC emissions vented to them with an efficiency of 95.0 percent or greater.

(c) Each enclosed combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) shall be designed to reduce the mass content of VOC emissions by 95.0 percent or greater in accordance with the requirements of section F(b).

(d) Flares used to comply with this subpart shall comply with the requirements of §60.18.

(e) Owners or operators of control devices used to comply with the provisions of this rule shall monitor these control devices to ensure that they are operated and maintained in conformance with their designs.

(f) Except as provided in paragraphs (i) through (k) of this section, each closed vent system shall be inspected according to the procedures and schedule specified in paragraphs (f)(1) and (2) of this section.

(1) If the vapor collection system or closed vent system is constructed of hard-piping, the owner or operator shall comply with the requirements specified in paragraphs (f)(1)(i) and (ii) of this section:

(i) Conduct an initial inspection according to the procedures in section G.7(b); and

(ii) Conduct annual visual inspections for visible, audible, or olfactory indications of leaks.

(2) If the vapor collection system or closed vent system is constructed of ductwork, the owner or operator shall:

(i) Conduct an initial inspection according to the procedures in section G.7(b); and

(ii) Conduct annual inspections according to the procedures in section G.7(b).

(g) Leaks, as indicated by an instrument reading greater than 500 ppmv above background or by visual inspections, shall be repaired as soon as practicable except as provided in paragraph (h) of this section.

(1) A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(2) Repair shall be completed no later than 15 calendar days after the leak is detected.

(h) Delay of repair of a closed vent system for which leaks have been detected is allowed if the repair is technically infeasible without a process unit shutdown or if the owner or operator determines that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. Repair of such equipment shall be complete by the end of the next process unit shutdown.

(i) If a vapor collection system or closed vent system is operated under a vacuum, it is exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section.

(j) Any parts of the closed vent system that are designated, as described in paragraph (l)(1) of this section, as unsafe to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (j)(1) and (2) of this section:

(1) The owner or operator determines that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (f)(1)(i) or (f)(2) of this section; and

(2) The owner or operator has a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(k) Any parts of the closed vent system that are designated, as described in paragraph (l)(2) of this section, as difficult to inspect are exempt from the inspection requirements of paragraphs (f)(1)(i) and (f)(2) of this section if they comply with the requirements specified in paragraphs (k)(1) through (3) of this section:

(1) The owner or operator determines that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface; and

(2) The owner or operator designates less than 3.0 percent of the total number of closed vent system equipment as difficult to inspect; and

(3) The owner or operator has a written plan that requires inspection of the equipment at least once every 5 years. A closed vent system is exempt from inspection if it is operated under a vacuum.

(l) The owner or operator shall record the information specified in paragraphs (l)(1) through (5) of this section.

(1) Identification of all parts of the closed vent system that are designated as unsafe to inspect, an explanation of why the equipment is unsafe to inspect, and the plan for inspecting the equipment.

(2) Identification of all parts of the closed vent system that are designated as difficult to inspect, an explanation of why the equipment is difficult to inspect, and the plan for inspecting the equipment.

(3) For each inspection during which a leak is detected, a record of the information specified in section G.8(a)(3).

(4) For each inspection conducted in accordance with section G.7(b) during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(5) For each visual inspection conducted in accordance with paragraph (f)(1)(ii) of this section during which no leaks are detected, a record that the inspection was performed, the date of the inspection, and a statement that no leaks were detected.

(m) Closed vent systems and control devices used to comply with provisions of this rule shall be operated at all times when emissions may be vented to them.

G.5.9 What VOC Emission Control Requirements Apply to Connectors in Gas/Vapor Service and in Light Liquid Service?

(a) The owner or operator shall initially monitor all connectors in the process unit for leaks within 12 months of the compliance date. If all connectors in the process unit have been monitored for leaks prior to the compliance date, no initial monitoring is required provided either no process changes have been made since the monitoring or the owner or operator can determine that the results of the monitoring, with or without adjustments, reliably demonstrate compliance despite process changes. If required to monitor because of a process change, the owner or operator is required to monitor only those connectors involved in the process change.

(b) Except as allowed in section G.5.7 or as specified in paragraph (e) of this section, the owner or operator shall monitor all connectors in gas and vapor and light liquid service as specified in paragraphs (a) and (b)(3) of this section.

(1) The connectors shall be monitored to detect leaks by the method specified in section G.7(b) and, as applicable, section G.7(c).

(2) If an instrument reading greater than or equal to 500 ppm is measured, a leak is detected.

(3) The owner or operator shall perform monitoring, subsequent to the initial monitoring required in paragraph (a) of this section, as specified in paragraphs (b)(3)(i) through (iii) of this section, and shall comply with the requirements of paragraphs (b)(3)(iv) and (v) of this section. The required period in which monitoring must be conducted shall be determined from paragraphs (b)(3)(i) through (iii) of this section using the monitoring results from the preceding monitoring period. The percent leaking connectors shall be calculated as specified in paragraph (c) of this section.

(i) If the percent leaking connectors in the process unit was greater than or equal to 0.5 percent, then monitor within 12 months (1 year).

(ii) If the percent leaking connectors in the process unit was greater than or equal to 0.25 percent but less than 0.5 percent, then monitor within 4 years. An owner or operator may comply with the requirements of this paragraph by monitoring at least 40 percent of the connectors within 2 years of the start of the monitoring period, provided all connectors have been monitored by the end of the 4-year monitoring period.

(iii) If the percent leaking connectors in the process unit was less than 0.25 percent, then monitor as provided in paragraph (b)(3)(iii)(A) of this section and either paragraph (b)(3)(iii)(B) or (b)(3)(iii)(C) of this section, as appropriate.

(A) An owner or operator shall monitor at least 50 percent of the connectors within 4 years of the start of the monitoring period.

(B) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is greater than or equal to 0.35 percent of the monitored connectors, the owner or operator shall monitor as soon as practical, but within the next 6

months, all connectors that have not yet been monitored during the monitoring period. At the conclusion of monitoring, a new monitoring period shall be started pursuant to paragraph (b)(3) of this section, based on the percent of leaking connectors within the total monitored connectors.

(C) If the percent of leaking connectors calculated from the monitoring results in paragraph (b)(3)(iii)(A) of this section is less than 0.35 percent of the monitored connectors, the owner or operator shall monitor all connectors that have not yet been monitored within 8 years of the start of the monitoring period.

(iv) If, during the monitoring conducted pursuant to paragraphs (b)(3)(i) through (iii) of this section, a connector is found to be leaking, it shall be re-monitored once within 90 days after repair to confirm that it is not leaking.

(v) The owner or operator shall keep a record of the start date and end date of each monitoring period under this section for each process unit.

(c) For use in determining the monitoring frequency, as specified in paragraphs (a) and (b)(3) of this section, the percent leaking connectors as used in paragraphs (a) and (b)(3) of this section shall be calculated by using the following equation:

$$\%C_L = C_L / C_t * 100$$

Where:

$\%C_L$ = Percent of leaking connectors as determined through periodic monitoring required in paragraphs (a) and (b)(3)(i) through (iii) of this section.

C_L = Number of connectors measured at 500 ppm or greater, by the method specified in G.7(b).

C_t = Total number of monitored connectors in the process unit.

(d) When a leak is detected pursuant to paragraphs (a) and (b) of this section, it shall be repaired as soon as practicable, but not later than 15 calendar days after it is detected, except as

provided in section G.5.7. A first attempt at repair as defined in this rule shall be made no later than 5 calendar days after the leak is detected.

(e) Any connector that is designated, as described in section G.8(a)(6)(i), as an unsafe-to-monitor connector is exempt from the requirements of paragraphs (a) and (b) of this section if:

(1) The owner or operator of the connector demonstrates that the connector is unsafe-to-monitor because monitoring personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (a) and (b) of this section; and

(2) The owner or operator of the connector has a written plan that requires monitoring of the connector as frequently as practicable during safe-to-monitor times, but not more frequently than the periodic monitoring schedule otherwise applicable, and repair of the equipment according to the procedures in paragraph (d) of this section if a leak is detected.

(f) *Inaccessible, ceramic, or ceramic-lined connectors.* (1) Any connector that is inaccessible or that is ceramic or ceramic-lined (e.g., porcelain, glass, or glass-lined), is exempt from the monitoring requirements of paragraphs (a) and (b) of this section, from the leak repair requirements of paragraph (d) of this section, and from recordkeeping and reporting requirements. An inaccessible connector is one that meets any of the provisions specified in paragraphs (f)(1)(i) through (vi) of this section, as applicable:

(i) Buried;

(ii) Insulated in a manner that prevents access to the connector by a monitor probe;

(iii) Obstructed by equipment or piping that prevents access to the connector by a monitor probe;

(iv) Unable to be reached from a wheeled scissor-lift or hydraulic-type scaffold that would allow access to connectors up to 7.6 meters (25 feet) above the ground;

(v) Inaccessible because it would require elevating the monitoring personnel more than 2 meters (7 feet) above a permanent support surface or would require the erection of scaffold; or

(vi) Not able to be accessed at any time in a safe manner to perform monitoring. Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines, or would risk damage to equipment.

(2) If any inaccessible, ceramic, or ceramic-lined connector is observed by visual, audible, olfactory, or other means to be leaking, the visual, audible, olfactory, or other indications of a leak to the atmosphere shall be eliminated as soon as practical.

(g) Except for instrumentation systems and inaccessible, ceramic, or ceramic-lined connectors meeting the provisions of paragraph (f) of this section, identify the connectors subject to the requirements of this rule. Connectors need not be individually identified if all connectors in a designated area or length of pipe subject to the provisions of this rule are identified as a group, and the number of connectors subject to the requirements is indicated.

G.6 Alternative Standards

G.6.1 Alternative Standards for Valves—Allowable Percentage of Valves Leaking

(a) An owner or operator may elect to comply with an allowable percentage of valves leaking of equal to or less than 2.0 percent.

(b) The following requirements shall be met if an owner or operator wishes to comply with an allowable percentage of valves leaking:

(1) An owner or operator must notify the permitting authority that the owner or operator has elected to comply with the allowable percentage of valves leaking before implementing this alternative standard, as specified in section G.8(b)(4).

(2) A performance test as specified in paragraph (c) of this section shall be conducted initially upon designation, annually, and at other times requested by the permitting authority.

(3) If a valve leak is detected, it shall be repaired in accordance with section G.5.5(d) and (e).

(c) Performance tests shall be conducted in the following manner:

(1) All valves in gas/vapor and light liquid service within the natural gas processing plant subject to VOC emission control requirements shall be monitored within one week by the methods specified in section G.7(b).

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3) The leak percentage shall be determined by dividing the number of valves for which leaks are detected by the number of valves in gas/vapor and light liquid service within the natural gas processing plant subject to VOC emission control requirements.

(d) Owners and operators who elect to comply with this alternative standard shall not have a natural gas processing plant subject to the equipment component VOC emission control requirements with a leak percentage greater than 2.0 percent, determined as described in section G.7(h).

G.6.2 Alternative Standards for Valves—Skip Period Leak Detection and Repair

(a)(1) An owner or operator may elect to comply with one of the alternative work practices specified in paragraphs (b)(2) and (3) of this section.

(2) An owner or operator must notify the permitting authority before implementing one of the alternative work practices.

(b)(1) An owner or operator shall comply initially with the requirements for valves in gas/vapor service and valves in light liquid service, as described in section G.5.5.

(2) After 2 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 1 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(3) After 5 consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0, an owner or operator may begin to skip 3 of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(4) If the percent of valves leaking is greater than 2.0, the owner or operator shall comply with the requirements as described in section G.5.5 but can again elect to use this section.

(5) The percent of valves leaking shall be determined as described in section G.7(h).

(6) An owner or operator must keep a record of the percent of valves found leaking during each leak detection period.

(7) A valve that begins operation in gas/vapor service or light liquid service after the compliance date for a process unit following one of the alternative standards in this section must be monitored in accordance with section G.5.5(a)(2)(i) or (ii) before the provisions of this section can be applied to that valve.

G.7 Equipment Leak Test Methods and Procedures

(a) In conducting the performance tests, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section.

(b) The owner or operator shall determine compliance with the standards in sections G.5.2 through G.5.9, and as follows:

(1) EPA Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in EPA Method 21 of appendix A-7 of this part. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored. If the monitoring

instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring, the owner or operator need not calibrate the scales that will not be used during that day's monitoring.

(2) A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in EPA Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in section G.8(a)(5)(v). Divide these readings by the initial calibration value and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by $(100 \text{ minus the percent of negative drift} / \text{divided by } 100)$ must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by $(100 \text{ plus the percent of positive drift} / \text{divided by } 100)$ may be re-monitored.

(c) The owner or operator shall determine compliance with the no-detectable-emission standards in sections G.5.2, G.5.3(e), G.5.5(f), and G.5.8(e) as follows:

(1) The requirements of paragraph (b) shall apply.

(2) EPA Method 21 of appendix A-7 of this part shall be used to determine the background level. All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is compared with 500 ppm for determining compliance.

(d) The owner or operator shall test each piece of equipment unless he demonstrates that a process unit is not in VOC service, i.e., that the VOC content would never be reasonably expected to exceed 10 percent by weight. For purposes of this demonstration, the following methods and procedures shall be used:

(1) Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 must be used.

(2) Organic compounds that are considered by the permitting authority to have negligible photochemical reactivity may be excluded from the total quantity of organic compounds in determining the VOC content of the process fluid.

(3) Engineering judgment may be used to estimate the VOC content, if a piece of equipment had not been shown previously to be in service. If the permitting authority disagrees with the judgment, paragraphs (d)(1) and (2) of this section shall be used to resolve the disagreement.

(e) The owner or operator shall demonstrate that a piece of equipment is in light liquid service by showing that all the following conditions apply:

(1) The vapor pressure of one or more of the organic components is greater than 0.3 kPa at 20 °C (1.2 in. H₂O at 68 °F). Standard reference texts or ASTM D2879-83, 96, or 97 shall be used to determine the vapor pressures.

(2) The total concentration of the pure organic components having a vapor pressure greater than 0.3 kPa at 20 °C (1.2 in. H₂O at 68 °F) is equal to or greater than 20 percent by weight.

(3) The fluid is a liquid at operating conditions.

(f) Samples used in conjunction with paragraphs (d), (e), and (g) of this section shall be representative of the process fluid that is contained in or contacts the equipment or the gas being combusted in the flare.

(g) The owner or operator shall determine compliance with the standards of flares as follows:

(1) EPA Method 22 of appendix A-7 of this part shall be used to determine visible emissions.

(2) A thermocouple or any other equivalent device¹⁶⁰ shall be used to monitor the presence of a pilot flame in the flare.

(3) The maximum permitted velocity for air assisted flares shall be computed using the following equation:

$$V_{\max} = K_1 + K_2 H_T$$

Where:

$V_{\max}$ = Maximum permitted velocity, m/sec (ft/sec).

H_T = Net heating value of the gas being combusted, MJ/scm (Btu/scf).

K_1 = 8.706 m/sec (metric units) = 28.56 ft/sec (English units).

K_2 = 0.7084 m⁴/(MJ-sec) (metric units) = 0.087 ft⁴/(Btu-sec) (English units).

¹⁶⁰ The equivalent device must be reviewed and approved by EPA through the SIP review process.

(4) The net heating value (H_T) of the gas being combusted in a flare shall be computed using the following equation:

$$H_T = K \sum_{i=1}^n C_i H_i$$

Where:

K = Conversion constant, 1.740×10^{-7} (g-mole)(MJ)/(ppm-scm-kcal) (metric units) = 4.674×10^{-6} [(g-mole)(Btu)/(ppm-scf-kcal)] (English units).

C_i = Concentration of sample component “i,” ppm

H_i = net heat of combustion of sample component “i” at 25°C and 760 mm Hg (77°F and 14.7 psi), kcal/g-mole.

(5) EPA Method 18 of appendix A-6 of this part or ASTM D6420-99 (2004) (where the target compound(s) are those listed in Section 1.1 of ASTM D6420-99, and the target concentration is between 150 parts per billion by volume and 100 ppmv) and ASTM D2504-67, 77, or 88 (Reapproved 1993) shall be used to determine the concentration of sample component “i.”

(6) ASTM D2382-76 or 88 or D4809-95 shall be used to determine the net heat of combustion of component “i” if published values are not available or cannot be calculated.

(7) EPA Method 2, 2A, 2C, or 2D of appendix A-7 of this part, as appropriate, shall be used to determine the actual exit velocity of a flare. If needed, the unobstructed (free) cross-sectional area of the flare tip shall be used.

(h) The owner or operator shall determine compliance with section G.6.1 or section G.6.2 as follows:

(1) The percent of valves leaking shall be determined using the following equation:

$$\%V_L = (V_L / V_T) * 100$$

Where:

$\%V_L$ = Percent leaking valves.

V_L = Number of valves found leaking.

V_T = The sum of the total number of valves monitored.

(2) The total number of valves monitored shall include difficult-to-monitor and unsafe-to-monitor valves only during the monitoring period in which those valves are monitored.

(3) The number of valves leaking shall include valves for which repair has been delayed.

(4) Any new valve that is not monitored within 30 days of being placed in service shall be included in the number of valves leaking and the total number of valves monitored for the monitoring period in which the valve is placed in service.

(5) If the process unit has been subdivided in accordance with section G.5.5(c)(1)(ii), the sum of valves found leaking during a monitoring period includes all subgroups.

(6) The total number of valves monitored does not include a valve monitored to verify repair.

G.8 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements.* Each owner or operator subject to the VOC equipment leak requirements specified in section G shall maintain the records specified in paragraphs (a)(1) through (10), as applicable, onsite or at the nearest local field office for at least five years.

(1) An owner or operator of more than one facility subject to the requirements of section G may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility.

(2) The owner or operator shall record the information specified in paragraphs (a)(2)(i) through (v) of this section for each monitoring event required by sections G.5.3, G.5.5, G.5.6, G.5.9, and G.6.2.

(i) Monitoring instrument identification.

(ii) Operator identification.

(iii) Equipment identification.

(iv) Date of monitoring.

(v) Instrument reading.

(3) When each leak is detected as specified in sections G.5.3, G.5.5, G.5.6, G.5.9, and G.6.2, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) Maximum instrument reading measured by EPA Method 21 of appendix A-7 of this part at the time the leak is successfully repaired or determined to be non-repairable, except when a pump is repaired by eliminating indications of liquids dripping.

(v) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(4) The following information pertaining to the design requirements for closed vent systems and control devices described in section G.5.8 shall be recorded and kept in a readily accessible location:

(i) Detailed schematics, design specifications, and piping and instrumentation diagrams.

(ii) The dates and descriptions of any changes in the design specifications.

(iii) A description of the parameter or parameters monitored, as required in section G.5.8(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.

(iv) Periods when the closed vent systems and control devices required in sections G.5.2 and G.5.3 are not operated as designed, including periods when a flare pilot light does not have a flame.

(v) Dates of startups and shutdowns of the closed vent systems and control devices required in sections G.5.2 and G.5.3.

(5) The following information pertaining to all equipment subject to the requirements in sections G.5.1 to G.5.9 shall be recorded in a log that is kept in a readily accessible location:

(i) A list of identification numbers for equipment subject to the requirements of this rule.

(ii)(A) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of sections G.5.3(e) and G.5.5(f).

(B) The designation of equipment as subject to the requirements of sections G.5.3(e) or section G.5.5(f) shall be signed by the owner or operator. Alternatively, owner or operator may establish a mechanism¹⁶¹ with their permitting authority that satisfies this requirement.

(C) A list of equipment identification numbers for pressure relief devices required to comply with section G.5.2.

(iii)(A) The dates of each compliance test as required in sections G.5.2, G.5.3(e), and G.5.5(f).

(B) The background level measured during each compliance test.

(C) The maximum instrument reading measured at the equipment during each compliance test.

(iv) A list of identification numbers for equipment in vacuum service.

(v) Records of the information specified in paragraphs (a)(5)(v)(A) through (F) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of EPA Method 21 of appendix A-7 of this part and section G.7(b).

(A) Date of calibration and initials of operator performing the calibration.

(B) Calibration gas cylinder identification, certification date, and certified concentration.

(C) Instrument scale(s) used.

(D) A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of EPA Method 21 of appendix A-7 of this part.

¹⁶¹ The mechanism must be reviewed and approved by EPA through the SIP review process.

(E) Results of each calibration drift assessment required by section G.7(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).

(F) If an owner or operator makes their own calibration gas, a description of the procedure used.

(vi) The connector monitoring schedule for each process unit as specified in section G.5.9(b)(3)(v).

(vii) Records of each release from a pressure relief device subject to section G.5.2.

(6) The following information pertaining to all valves subject to the requirements of section G.5.5(g) and (h), all pumps subject to the requirements of section G.5.3(g), and all connectors subject to the requirements of section G.5.9(e) shall be recorded in a log that is kept in a readily accessible location:

(i) A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

(ii) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.

(7) The following information shall be recorded for valves complying with section G.6.2:

(i) A schedule of monitoring.

(ii) The percent of valves found leaking during each monitoring period.

(8) The following information shall be recorded in a log that is kept in a readily accessible location:

(i) Design criterion required in section G.5.3(d)(5) and explanation of the design criterion; and

(ii) Any changes to this criterion and the reasons for the changes.

(A) The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions:

(1) An analysis demonstrating the design capacity of the natural gas processing plant,

(2) A statement listing the feed or raw materials and products from the processing plant(s) and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and

(3) An analysis demonstrating that equipment is not in VOC service.

(9) Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location.

(10) The following recordkeeping requirements apply to pumps in light liquid service, pressure relief devices in gas/vapor service, valves in gas/vapor service and light liquid service, pumps, valves and connectors in light heavy liquid service and pressure relief devices in light liquid or heavy liquid service, connectors in gas/vapor service and in light liquid service, and alternative standards for valves.

(i) When each leak is detected, as specified in section G.5.2, G.5.3(b)(2), G.5.5, G.5.6, G.5.9 and G.6.2, a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(ii) When each leak is detected, as specified in section G.5.2, G.5.3(b)(2), G.5.5, G.5.6, G.5.9 and G.6.2, the following information must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(A) The instrument and operator identification numbers and the equipment identification number.

(B) The date the leak was detected and the dates of each attempt to repair the leak.

(C) Repair methods applied in each attempt to repair the leak.

(D) “Above 500 ppm” if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 500 ppm or greater.

(E) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(F) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(G) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(H) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(I) The date of successful repair of the leak.

(J) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of section G.5. The designation of equipment that has no detectable emissions that is subject to the provisions of section G.5 must be signed by the owner or operator.

(b) *Reporting requirements.* Each owner or operator subject to the VOC equipment leak requirements shall comply with the reporting requirements of paragraphs (b)(1) through (5).

(1) Each owner or operator subject to the equipment leak VOC emission control requirements of section G.5 shall submit semiannual reports to the permitting authority beginning 6 months after a facility becomes subject to VOC emission control requirements of section G.5.8.

(2) The initial semiannual report to the permitting authority shall include the following information:

(i) Process unit identification.

(ii) Number of valves subject to the requirements of section G.5.5, excluding those valves designated for no detectable emissions under the provisions of section G.5.5(f).

(iii) Number of pumps subject to the requirements of section G.5.3, excluding those pumps designated for no detectable emissions under the provisions of section G.5.3(e) and those pumps complying with section G.5.3(f).

(iv) Number of connectors subject to the requirements of section G.5.9.

(v) Number of pressure relief devices subject to the requirements, except for those pressure relief devices designated for no detectable emissions under the provisions of section G.5.2 (a) and those pressure relief devices complying with section G.5.2 (c).

(3) All semiannual reports to the permitting authority shall include the following information:

(i) Process unit identification.

(ii) For each month during the semiannual reporting period,

(A) Number of valves for which leaks were detected as described in section G.5.5(b) or section G.6.2,

(B) Number of valves for which leaks were not repaired as required in section G.5.5(d)(1),

(C) Number of pumps for which leaks were detected as described in section G.5.3(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),

(D) Number of pumps for which leaks were not repaired as required in section G.5.3(c)(1) and (d)(6),

(E) Number of compressors for which leaks were detected as described in section G.5.3(f),

(F) Number of connectors for which leaks were detected as described in section G.5.9(b)

(G) Number of connectors for which leaks were not repaired as required in section G.5.9(d), and

(H) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

(iii) An owner or operator must include the following information in all semiannual reports:

(A) Number of pressure relief devices for which leaks were detected; and

(B) Number of pressure relief devices for which leaks were not repaired.

(iv) Dates of process unit shutdowns which occurred within the semiannual reporting period.

(v) Revisions to items reported according to paragraph (b)(1) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.

(4) An owner or operator electing to comply with the provisions of section G.6.1 or section G.6.2 shall notify the permitting authority of the alternative standard selected 90 days before implementing either of the provisions.

(5) An owner or operator shall report the results of all performance tests to the permitting authority.

G.9 Definitions

As used in this model rule, all terms not defined in section G for equipment leaks at natural gas processing plants shall have the meaning given them in subpart VVa of part 60 and the following terms shall have the specific meanings given them.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

Equipment, as used in the standards and requirements in this rule relative to the equipment leaks of VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this rule.

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used transport field gas from a field to the main pipeline in the area.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Completion combustion devices include pit flares.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Gas processing plant process unit means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in sections G.7(e) and G.3(e)(2).

In wet gas service means that a piece of equipment (except compressors and sampling connection systems) contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Non-fractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Underground storage vessel means a storage vessel stored below ground.

H Pneumatic Pumps: VOC Emissions Control Requirements

H.1 Applicability

Each pneumatic pump, which is a natural gas-driven diaphragm pump located at:

(a) A natural gas processing plant; or

(b) A well site. A natural gas-driven diaphragm pump at a well site that is in operation less than 90 days per calendar year is not a source subject to VOC requirements under this rule provided that the owner/operator keeps records of the days of operation each calendar year and submits such records to the regulatory authority upon request. For the purposes of this rule, any period of operation during a calendar day counts toward the 90 calendar day threshold.

For purposes of the requirements specified in this section, we refer to these pumps as natural gas-driven pneumatic pumps.

H.2 What VOC Emission Reduction Requirements Apply to Natural Gas-Driven Pneumatic Pumps?

For each natural gas-driven pneumatic pump, you must comply with the VOC emission control requirements, based on VOC, in either paragraph (a) or (b)(1) of this section, as applicable.

(a) Each natural gas-driven pneumatic pump at a natural gas processing plant must have a VOC emission rate of zero.

(b)(1) For each natural gas-driven pneumatic pump at a well site, you must reduce natural gas emissions by 95.0 percent, except as provided in paragraphs (b)(2), (3) and (4) of this section.

(2) You are not required to install a control device solely for the purpose of complying with the 95.0 percent reduction requirement of paragraph (b)(1) of this section. If you do not

have a control device installed on site by the compliance date established by your regulatory authority and you do not have the ability to route to a process, then you must comply instead with the provisions of paragraph (b)(2)(i) and (ii) of this section.

(i) Submit a certification in accordance with section H.5(b)(1)(i) in your next annual report, certifying that there is no available control device or process on site and maintain the records in section H.5(a)(1)(i) and (ii).

(ii) If you subsequently install a control device or have the ability to route to a process, you are no longer required to submit the certification in section H.2(b)(2)(i) and must submit the information in section H.5(b)(2) in your next annual report and maintain the records in sections H.5(a)(1)(i), (ii) and (iii) and H.5(a)(2). You must be in compliance with the requirements of paragraph (b)(1) of this section within 30 days of startup of the control device or within 30 days of the ability to route to a process.

(3) If the control device available on site is unable to achieve a 95.0 percent reduction and there is no ability to route the emissions to a process, you must still route the natural gas-driven pneumatic pump's emissions to that existing control device. If you route the pneumatic pump to a control device installed on site that is designed to achieve less than a 95.0 percent reduction, you must submit the information specified in section H.5(b)(1)(iii) in your next annual report and maintain the records in sections H.5(a)(1)(i), (ii) and (iii) and H.5(a)(2).

(4) If you determine, through an engineering assessment, that routing a pneumatic pump to a control device or a process is technically infeasible, the requirements specified in paragraph (b)(4)(i) through (iv) of this section must be met.

(i) You must conduct the assessment of technical infeasibility in accordance with the criteria in paragraph (b)(4)(iii) of this section and have it certified by a qualified professional engineer in accordance with paragraph (b)(4)(ii) of this section.

(ii) The following certification, signed and dated by the qualified professional engineer shall state: "I certify that the assessment of technical infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted and this report was

prepared pursuant to the requirements of section H.2(b)(4)(iii) of this rule. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information.”

(iii) The assessment of technical feasibility to route emissions from the pneumatic pump to an existing control device on site or to a process must include, but is not limited to, safety considerations, distance from the control device, pressure losses and differentials in the closed vent system and the ability of the control device to handle the pneumatic pump emissions which are routed to them. You must prepare the assessment of technical infeasibility under the direction or supervision of the qualified professional engineer who signs the certification in accordance with paragraph (b)(2)(ii) of this section.

(iv) You must maintain the records specified in section H.5(a)(1)(iv).

(5) If the pneumatic pump is routed to a control device or a process and the control device or process is subsequently removed from the location or is no longer available, you are no longer required to be in compliance with the requirements of paragraph (b)(1) of this section, and instead must comply with paragraph (b)(2) of this section and report the change in your next annual report in accordance with section H.5(b)(2)(iii).

(c) If you use a control device or route to a process to reduce emissions, you must connect the natural gas-driven pneumatic pump subject to VOC emission control requirements through a closed vent system that meets the requirements of section D.1(b).

(d) You must demonstrate initial compliance with standards that apply to natural gas-driven pneumatic pumps subject to VOC emission requirements as required by section H.3.

(e) You must demonstrate continuous compliance with standards that apply to natural gas-driven pneumatic pump sources subject to VOC emission requirements as required by section H.4.

(f) You must perform the reporting as required by section H.5(b) and the recordkeeping as required by H.5(a).

H.3 Initial Compliance Demonstration Requirements

You must demonstrate initial compliance by the compliance date established by your regulatory authority by demonstrating compliance with the VOC emission control requirements for natural gas-driven pneumatic pumps specified in paragraphs (a) through (h) of this section, as applicable.

(a) If you own or operate a pneumatic pump located at a natural gas processing plant, your pneumatic pump must be driven by a gas other than natural gas, resulting in zero VOC emissions.

(b) If you own or operate a natural gas-driven pneumatic pump located at a well site, you must reduce emissions in accordance with section H.2(b)(1), and you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of section D.1(b).

(c) If you own or operate a natural gas-driven pneumatic pump located at a well site and there is no control device or process available on site, you must submit the certification in section H.5(b)(1)(i).

(d) If you own or operate a natural gas-driven pneumatic pump located at a well site, and you are unable to route to an existing control device due to technical infeasibility, and you are unable to route to a process, you must submit the certification in section H.5(b)(1)(ii).

(e) If you own or operate a natural gas-driven pneumatic pump located at a well site and you reduce emissions in accordance with section H.2(b)(3), you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of section D.1(b).

(f) If you are required to collect emissions from a natural gas-driven pneumatic pump through a closed vent system, you must conduct the initial closed vent system inspection required in section D.2 by the date established by your regulatory authority.

(g) You must include a listing of the natural gas-driven pneumatic pumps subject to VOC emission requirements specified in paragraphs (a) through (e) of this section in the initial annual report submitted for your natural gas-driven pneumatic pump according to the requirements of section H.5(b).

(h) You must maintain the records as specified in section H.5(a) for each natural gas-driven pneumatic pump subject to the VOC emission control requirements of section H.

H.4 Continuous Compliance Demonstration Requirements

For each natural gas-driven pneumatic pump you must demonstrate continuous compliance according to paragraphs (a) and (b) of this section.

(a) If you are required to collect emissions from a natural gas-driven pneumatic pump through a closed vent system, you must conduct the periodic closed vent system inspections required in section D.2, as applicable.

(b) You must submit the annual reports required by section H.5(b) and maintain the records as specified in section H.5(a).

H.5 Recordkeeping and Reporting Requirements

(a) *Recordkeeping requirements.*

(1) For each natural gas-driven pneumatic pump subject to VOC emission control requirements, you must maintain the records identified in paragraphs (a)(1)(i) through (v) of this section, as applicable, onsite or at the nearest local field office for at least five years.

(i) Records of the date that an individual natural gas-driven pneumatic pump is required to comply with the rule (as established by the regulatory authority), location and manufacturer specifications for each natural gas-driven pneumatic pump.

(ii) Records of deviations in cases where the natural gas-driven pneumatic pump was not operated in compliance with the requirements specified in section H.2.

(iii) Records on the control device used for control of emissions from a natural gas-driven pneumatic pump including the installation date, manufacturer's specifications, and if the control device is designed to achieve less than a 95.0 percent emission reduction, a design evaluation or manufacturer's specifications indicating the percentage reduction the control device is designed to achieve.

(iv) Records substantiating a claim according to H.2(b)(4) that it is technically infeasible to capture and route emissions from a pneumatic pump to a control device or process, including the qualified professional engineer certification according to H.2(b)(4)(ii) and the records of the engineering assessment of technical infeasibility performed according to H.2.(b)(4)(iii).

(v) You must retain copies of all certifications, engineering assessments and related records for a period of five years and make them available if directed by the regulatory authority.

(2) If you are required to collect emissions from a natural gas-driven pneumatic pump through a closed vent system, you must maintain the records identified in paragraphs (a)(2)(i) through (iv) of this section, as applicable, onsite or at the nearest local field office for at least five years.

(i) Records of each closed vent system inspection required under section D.2(a) and (b).

(ii) If you are subject to the bypass requirements of section D.1(b)(3), a record of each inspection or a record of each time the key is checked out or a record of each time the alarm is sounded.

(iii) If you are subject to the closed vent system no detectable emissions requirements of section D.2(e), records of the monitoring conducted in accordance with section D.2(e).

(iv) For each closed vent system routing to a control device or process, the records of the assessment conducted according to section D.1(b)(4):

(A) A copy of the assessment conducted according to section D.1(b)(4);

(B) A copy of the certification according to section D.1(b)(4)(i); and

(C) The owner or operator shall retain copies of all certifications, assessments and any related records for a period of five years, and make them available if directed by the regulatory authority.

(b) Reporting Requirements.

For each natural gas-driven pneumatic pump subject to VOC emission control requirements, annual reports are required to include the information specified in paragraphs (b)(1) through (4) of this section.

(1) In the initial annual report, a certification that the natural gas-driven pneumatic pump meets one of the conditions described in paragraphs (b)(1)(i), (ii) or (iii) of this section.

(i) No control device or process is available on site.

(ii) A control device or process is available on site and the owner or operator has determined in accordance with H.2(b)(4) that it is technically infeasible to capture and route the emissions to the control device or process.

(iii) Emissions from the natural gas-driven pneumatic pump are routed to a control device or process. If the control device is designed to achieve less than 95.0 percent emissions reduction, specify the percent emissions reductions the control device is designed to achieve.

(2) For any natural gas-driven pneumatic pump which has been previously reported as required under paragraph (b)(1) of this section and for which a change in the reported condition has occurred during the reporting period, provide the identification of the natural gas-driven pneumatic pump and the date it was previously reported and a certification that the pneumatic pump meets one of the conditions described in paragraphs (b)(2)(i), (ii) or (iii) or (iv) of this section.

(i) A control device has been added to the location and the pneumatic pump now reports according to paragraph (b)(1)(iii) of this section.

(ii) A control device has been added to the location and the pneumatic pump now reports according to paragraph (b)(1)(ii) of this section.

(iii) A control device or process has been removed from the location or otherwise is no longer available and the pneumatic pump now report according to paragraph (b)(1)(i) of this section.

(iv) A control device or process has been removed from the location or is otherwise no longer available and the owner or operator has determined in accordance with H.2(b)(4) through an engineering evaluation that it is technically infeasible to capture and route the emissions to another control device or process.

(3) Records of deviations specified in paragraph (a)(1)(ii) of this section that occurred during the reporting period.

(4) If you are required to collect emissions from a natural gas-driven pneumatic pump through a closed vent system, the records specified in paragraphs (a)(2)(i), (ii), (iii) and (iv)(B) of this section.

H.6 Definitions

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding \$25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including, but not limited to, general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.*, a Regional Administrator of EPA); or

(4) For facilities subject to requirements:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Natural gas-driven diaphragm pump means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction

with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Qualified Professional Engineer means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in at least one state in which the certifying official is located.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process that is operational where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well.

I Fugitive Emissions Components VOC Emissions Control Requirements

I.1 Applicability

(a) The collection of fugitive emission components at a well site with wells that produce, on average, greater than 15 barrel equivalents per day. The fugitive emissions requirements of this section do not apply to well sites that only contain wellheads. Whether a separate tank battery surface site is subject to this rule has no effect on the status of a well site that only contains wellheads.

(b) The collection of fugitive emission components at a gathering and boosting station located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or to an oil pipeline.

I.2 What VOC Emission Control Requirements Apply to the Collection of Fugitive Emission Components at a Well Site and a Gathering and Boosting Station?

For fugitive emissions, VOC emission control requirements apply to the collection of fugitive emission components at a well site and gathering and boosting station (that is located from the wellhead to the point of custody transfer to the natural gas transmission and storage segment or to an oil pipeline), as specified in paragraphs (a) through (f) of this section for monitoring the collection of fugitive emission components. These requirements are independent of the closed vent system and cover requirements in section D. The collection of fugitive emissions at a well site with a gas to oil ratio of less than 300 scf of gas per barrel of oil produced are subject only to the requirements in paragraph (g) of this section.

(a) You must monitor all fugitive emission components, as defined in section I.6, in accordance with paragraphs (b) through (e) of this section and section I.2(a) and I.3(a). You must

repair all sources of fugitive emissions in accordance with paragraph (f) of this section. You must keep records in accordance with section I.5(a) and report in accordance with section I.5(b). For purposes of this section, fugitive emissions are defined as: any visible emission from a fugitive emission component using optical gas imaging or an instrument reading of 500 ppm or greater using EPA Method 21.

(b) You must develop an emissions monitoring plan that covers the collection of fugitive emission components at well sites and gathering and boosting stations within each company-defined area in accordance with paragraphs (c) and (d) of this section.

(c) Fugitive emissions monitoring plans must include the elements specified in paragraphs (c)(1) through (c)(8) of this section, at a minimum.

(1) Frequency for conducting surveys. Monitoring surveys must be conducted at least as frequently as required by sections I.3 and section I.4 of this section.

(2) Technique for determining fugitive emissions (*i.e.*, EPA Method 21 at 40 CFR part 60, appendix A-7, or optical gas imaging).

(3) Manufacturer and model number of fugitive emission detection equipment to be used.

(4) Procedures and timeframes for identifying and fixing fugitive emission components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (f) of this section at a minimum.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) If you are using optical gas imaging, your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.

(i) Verification that your optical gas imaging equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification and may be performed by the facility, by the manufacturer, or by a third party. For purposes of complying with the fugitive emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.

(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.

(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤ 60 g/hr from a quarter inch diameter orifice.

(ii) Procedure for a daily verification check.

(iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

(iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

(v) Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (*e.g.*, steam).

(vi) Training and experience needed prior to performing surveys.

(vii) Procedures for calibration and maintenance. At a minimum, procedures must comply with those recommended by the manufacturer.

(8) If you are using EPA Method 21 at 40 CFR part 60, appendix A-7, your plan must also include the elements specified in paragraphs (c)(8)(i) and (ii) of this section. For the purposes of complying with the fugitive emissions monitoring program using EPA Method 21, a fugitive emission is defined as an instrument reading of 500 ppm or greater.

(i) Verification that your monitoring equipment meets the requirements specified in Section 6.0 of EPA Method 21 at 40 CFR part 60, appendix A-7. For purposes of instrument capability, the fugitive emissions definition shall be 500 ppm or greater methane using a FID-based instrument. If you wish to use an analyzer other than a FID-based instrument, you must develop a site-specific fugitive emission definition that would be equivalent to 500 ppm methane using a FID-based instrument (*e.g.*, 10.6 eV PID with a specified isobutylene concentration as the fugitive emission definition would provide equivalent response to your compound of interest).

(ii) Procedures for conducting surveys. At a minimum, the procedures shall ensure that the surveys comply with the relevant sections of EPA Method 21 at 40 CFR part 60, appendix A-7, including Section 8.3.1.

(d) Each fugitive emissions monitoring plan must include the elements specified in paragraphs (d)(1) through (d)(4) of this section, at a minimum, as applicable.

(1) Sitemap.

(2) If you are using OGI, a defined observation path that ensures that all fugitive emissions components are within sight of the path. The observation path must account for interferences.

(3) If you are using EPA Method 21, your plan must also include a list of fugitive emissions components to be monitored and the method for determining location of fugitive

emissions components to be monitored in the field (*e.g.*, tagging, identification on a process and instrumentation diagram, etc.).

(4) Your plan must also include the written plan developed for all of the fugitive emission components designated as difficult-to-monitor in accordance with section I.4(a)(3), and the written plan for fugitive emission components designated as unsafe-to-monitor in accordance with section I.4(a)(4).

(e) Each monitoring survey shall observe each fugitive emissions component, as defined section I.6, for fugitive emissions.

(f) Each identified source of fugitive emissions shall be repaired or replaced in accordance with paragraphs (f)(1) and (2) of this section. For fugitive emissions components also subject to the repair provisions of sections A.4(d)(4) through (7) and D.2(e)(9) through (12), those provisions apply instead to those closed vent system and covers, and the repair provisions of paragraphs (f)(1) and (2) of this section do not apply to those closed vent systems and covers.

(1) Each identified source of fugitive emissions shall be repaired or replaced as soon as practicable, but no later than 30 calendar days after detection of the fugitive emissions.

(2) If the repair or replacement is technically infeasible, would require a vent blowdown, a gathering and boosting station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next gathering and boosting station shutdown, well shutdown, well shut-in, after an unscheduled, planned or emergency vent blowdown or within 2 years, whichever is earlier.

(3) Each repaired or replaced fugitive emissions component must be resurveyed as soon as practical, but no later than 30 days after being repaired or replaced, to ensure that there are no fugitive emissions.

(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using EPA Method 21 or optical gas imaging within 30 days of being repaired.

(ii) For each repair or replacement that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken, must clearly identify the component by location within the site (*e.g.*, the latitude and longitude of the component or by other descriptive landmarks visible in the picture).

(iii) Operators that use EPA Method 21 to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (f)(3)(iii)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the EPA Method 21 instrument indicates a concentration of less than 500 ppm above background or when no soap bubbles are observed when the alternative screening procedures specified in section 8.3.3 of EPA Method 21 are used.

(B) Operators must use the EPA Method 21 monitoring requirements specified in paragraph (c)(8)(ii) of this section or the alternative screening procedures specified in section 8.3.3 of EPA Method 21.

(iv) Operators that use optical gas imaging to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (f)(3)(iv)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the optical gas imaging instrument shows no indication of visible emissions.

(B) Operators must use the optical gas imaging monitoring requirements specified in paragraph (c)(7) of this section.

(g) For each well with less than 300 scf of gas per stock tank barrel of oil produced, you must comply with paragraphs (g)(1) and (g)(2) of this section.

(1) You must determine the gas to oil ratio of your well using generally accepted methods.

(2) You must maintain the records specified in section I.5 (a)(4)

I.3 Initial Compliance Demonstration

To achieve initial compliance with the fugitive emission standards for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station, you must comply with paragraphs (a) through (e) or (f), if applicable, of this section.

(a) You must develop a fugitive emissions monitoring plan as required in sections I.2(b), (c), and (d).

(b) You must conduct an initial monitoring survey as required in paragraphs (b)(1) and (2), as applicable

(1) Each well site with a collection of fugitive emissions components must conduct an initial monitoring survey within 60 days of becoming subject to VOC emission control requirements of section I.

(2) Each gathering and boosting station with a collection of fugitive emissions components must conduct an initial monitoring survey within 60 days of being subject to VOC emission control requirements of section I.

(c) You must maintain the records specified in section I.5(a).

(d) You must repair or replace each identified source of fugitive emissions as required in section I.2(f).

(e) You must submit the initial annual report for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station as required in section I.5(b).

(f) You must determine the gas to oil ratio of your well using generally accepted methods and maintain the records specified in section I.5(a)(4).

I.4 Continuous Compliance Demonstration

For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station, you must demonstrate continuous compliance with the fugitive emission standards specified in section I.2 according to paragraphs (a) through (d) or (e), if applicable, of this section.

(a) You must conduct periodic monitoring surveys of each collection of fugitive emissions components at a well site and a gathering and boosting station subject to VOC emission control requirements under section I at the frequencies specified in paragraphs (a)(1) and (a)(2) of this section, with the exceptions noted in paragraphs (a)(3) through (a)(5) of this section.

(1) A monitoring survey of each collection of fugitive emissions components at a well site within a company-defined area must be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys must be conducted at least 4 months apart.

(2) A monitoring survey of the collection of fugitive emissions components at a gathering and boosting station within a company-defined area must be conducted at least quarterly after the initial survey. Consecutive quarterly monitoring surveys must be conducted at least 60 days apart.

(3) Fugitive emissions components that cannot be monitored without elevating the monitoring personnel more than 2 meters above the surface may be designated as difficult-to-monitor. Fugitive emissions components that are designated difficult-to-monitor must meet the specifications of paragraphs (a)(3)(i) through (iv) of this section.

(i) A written plan must be developed for all of the fugitive emissions components designated difficult-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by sections I.2(b), (c), and (d).

(ii) The plan must include the identification and location of each fugitive emissions component designated as difficult-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as difficult-to-monitor is difficult-to-monitor.

(iv) The plan must include a schedule for monitoring the difficult-to-monitor fugitive emissions components at least once per calendar year.

(4) Fugitive emissions components that cannot be monitored because monitoring personnel would be exposed to immediate danger while conducting a monitoring survey may be designated as unsafe-to-monitor. Fugitive emissions components that are designated unsafe-to-monitor must meet the specifications of paragraphs (a)(4)(i) through (iv) of this section.

(i) A written plan must be developed for all of the fugitive emissions components designated unsafe-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by sections I.2(b), (c), and (d).

(ii) The plan must include the identification and location of each fugitive emissions component designated as unsafe-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as unsafe-to-monitor is unsafe-to-monitor.

(iv) The plan must include a schedule for monitoring the fugitive emissions components designated as unsafe-to-monitor.

(5) The requirements of paragraph (a)(2) of this section are waived for any collection of fugitive emissions components at a gathering and boosting station located within an area that has an average calendar month temperature below 0°Fahrenheit for two of three consecutive calendar months of a quarterly monitoring period. The calendar month temperature average for each month within the quarterly monitoring period must be determined using historical monthly average temperatures over the previous three years as reported by a National Oceanic and Atmospheric Administration source or other source approved by the Administrator. The

requirements of paragraph (a)(2) of this section shall not be waived for two consecutive quarterly monitoring periods.

(b) You must repair or replace each identified source of fugitive emissions as required in section I.2(f).

(c) You must maintain the records specified in section I.5(a).

(d) You must submit annual reports for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station as required in section I.5(b).

(e) You must recalculate the gas to oil ratio of your well using generally accepted methods annually and maintain the records as required in section I.5(a)(4).

I.5 Recordkeeping and Reporting Requirements

(a) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a gathering and boosting station, the records identified in paragraphs (a)(1) through (3), and (a)(4), if applicable of this section shall be maintained onsite or at the nearest local field office for at least five years.

(1) The fugitive emissions monitoring plan as required in I.2(b), (c), and (d).

(2) The records of each monitoring survey as specified in paragraphs (a)(2)(i) through (ix) of this section.

(i) Date of the survey.

(ii) Beginning and end time of the survey.

(iii) Name of operator(s) performing survey. You must note the training and experience of the operator.

(iv) Monitoring instrument used.

(v) When optical gas imaging is used to perform the survey, one or more digital photographs or videos, captured from the optical gas imaging instrument used for conduct of monitoring, of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a gathering and boosting station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital file, the digital photograph or video may consist of an image of the monitoring survey being performed with a separately operating GPS device within the same digital picture or video, provided the latitude and longitude output of the GPS unit can be clearly read in the digital image.

(vi) Fugitive emissions component identification when EPA Method 21 is used to perform the monitoring survey.

(vii) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(viii) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(ix) Documentation of each fugitive emission, including the information specified in paragraphs (a)(2)(ix)(A) through (L) of this section.

(A) Location.

(B) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(C) Number and type of components for which fugitive emissions were detected.

(D) Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.

(E) Instrument reading of each fugitive emissions component that requires repair when EPA Method 21 is used for monitoring.

(F) Number and type of fugitive emissions components that were not repaired as required in section I.2(f).

(G) Number and type of components that were tagged as a result of not being repaired during the monitoring survey when the fugitive emissions were initially found as required in section I.2(f)(3)(ii).

(H) If a fugitive emissions component is not tagged, a digital photograph or video of each fugitive emissions component that could not be repaired during the monitoring survey when the fugitive emissions were initially found as required in section I.2(f)(3)(ii). The digital photograph or video must clearly identify the location of the component that must be repaired. Any digital photograph or video required under this paragraph can also be used to meet the requirements under paragraph (a)(2)(v) of this section, as long as the photograph or video is taken with the optical gas imaging instrument, includes the date and the latitude and longitude are either imbedded or visible in the picture.

(I) Repair methods applied in each attempt to repair the fugitive emissions components.

(J) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.

(K) The date of successful repair of the fugitive emissions component.

(L) Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

(3) For the collection of fugitive emissions components at a gathering and boosting station, if a monitoring survey is waived under section I.4(a)(5), you must maintain records of the average calendar month temperature, including the source of the information, for each calendar month of the quarterly monitoring period for which the monitoring survey was waived.

(4) For the collection of fugitive emissions at a well site with a gas to oil ratio of less than 300 scf per stock barrel of oil produced, you must maintain:

(A) A record of the gas to oil ratio analyses documenting a gas to oil ratio of less than 300 scf per stock barrel of oil produced, conducted pursuant to sections I.3(f) and I.4(e).

(B) The location of the well and the United States Well ID Number.

(C) A record of the determination signed by the certifying official. The claim must include a certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

(b) Annual reports shall be submitted for the collection of fugitive emissions components at each well site and the collection of fugitive emissions components at each gathering and boosting station within the company-defined area, that are subject to VOC emission control requirements under section I. Each annual report shall include the records of each monitoring survey including the information specified in paragraphs (b)(1) through (12) of this section. For the collection of fugitive emissions components at a gathering and boosting station, if a monitoring survey is waived under section I.4(a)(5), you must include in your annual report the fact that a monitoring survey was waived and the calendar months that make up the quarterly monitoring period for which the monitoring survey was waived. Multiple collection of fugitive emissions components at a well site or collection of fugitive emissions as a gathering and boosting station subject to VOC emission control requirements under section I may be included in a single annual report.

(1) Date of the survey.

(2) Beginning and end time of the survey.

(3) Name of operator(s) performing survey. If the survey is performed by optical gas imaging, you must note the training and experience of the operator.

(4) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(5) Monitoring instrument used.

(6) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(7) Number and type of components for which fugitive emissions were detected.

(8) Number and type of fugitive emissions components that were not repaired as required in section I.2(f).

(9) Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.

(10) The date of successful repair of the fugitive emissions component.

(11) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.

(12) Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

I.6 Definitions

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding \$25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including, but not limited to, general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.*, a Regional Administrator of EPA); or

(4) For facilities subject to requirements:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Gathering and boosting station means any permanent combination of one or more compressors that collects natural gas from well sites and moves the natural gas at increased pressure into gathering pipelines to the natural gas processing plant or into the pipeline. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a gathering and boosting station for purposes of this section.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Intermediate hydrocarbon liquid means any naturally occurring, unrefined petroleum liquid.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Fugitive emissions component means any component that has the potential to emit fugitive emissions of VOC at a well site or gathering and boosting station including, but not limited to, valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to section A.2(c) or (d) or section D, thief hatches or other openings on a controlled storage vessel not subject to section A, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of the fugitive emissions standards at section I.1, well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (*e.g.*, centralized tank batteries).

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

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Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After August 23, 2011, and on or Before September 18, 2015

§60.5360 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO₂) emissions from affected facilities in the crude oil and natural gas production source category that commence construction, modification, or reconstruction after August 23, 2011, and on or before September 18, 2015.

[85 FR 57069, Sept. 14, 2020]

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§60.5365 Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (g) of this section that is located within the Crude Oil and Natural Gas Production source category, as defined in §60.5430 for which you commence construction, modification, or reconstruction after August 23, 2011, and on or before September 18, 2015.

(a) Each gas well affected facility, which is a single natural gas well.

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(d)(1) For the oil and natural gas production segment, each pneumatic controller affected facility, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 standard cubic feet per hour.

(2) [Reserved]

(3) For natural gas processing plants, each pneumatic controller affected facility, which is a single continuous bleed natural gas-driven pneumatic controller.

(e) Each storage vessel affected facility, which is a single storage vessel, and has the potential for VOC emissions equal to or greater than 6 tons per year (tpy) as determined according to this section by October 15, 2013, for Group 1 storage vessels and by April 15, 2014, or 30 days after startup (whichever is later) for Group 2 storage vessels, except as provided in paragraphs (e)(1) through (4) of this section. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in this section. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a Federal, State, local or tribal authority.

(1) For each new, modified or reconstructed storage vessel receiving liquids pursuant to the standards for gas well affected facilities in §60.5375, including wells subject to §60.5375(f), you must determine the potential for VOC emissions within 30 days after startup of production.

(2) A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy shall remain an affected facility under this subpart.

(3) For storage vessels not subject to a legally and practically enforceable limit in an operating permit or other requirement established under Federal, state, local or tribal authority, any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of VOC potential to emit for purposes of determining affected facility status, provided you comply with the requirements in paragraphs (e)(3)(i) through (iv) of this section.

(i) You meet the cover requirements specified in §60.5411(b).

(ii) You meet the closed vent system requirements specified in §60.5411(c).

(iii) You maintain records that document compliance with paragraphs (e)(3)(i) and (ii) of this section.

(iv) In the event of removal of apparatus that recovers and routes vapor to a process, or operation that is inconsistent with the conditions specified in paragraphs (e)(3)(i) and (ii) of this section, you must determine the storage vessel's potential for VOC emissions according to this section within 30 days of such removal or operation.

(4) The following requirements apply immediately upon startup, startup of production, or return to service. A storage vessel affected facility that is reconnected to the original source of liquids is a storage vessel affected facility subject to the same requirements that applied before being removed from service. Any storage vessel that is used to replace any storage vessel affected facility is subject to the same requirements that apply to the storage vessel affected facility being replaced.

(5) A storage vessel with a capacity greater than 100,000 gallons used to recycle water that has been passed through two stage separation is not a storage vessel affected facility.

(f) The group of all equipment, except compressors, within a process unit is an affected facility.

(1) Addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(2) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit is covered by §§60.5400, 60.5401, 60.5402, 60.5421, and 60.5422 of this subpart if it is located at an onshore natural gas processing plant. Equipment not located at the onshore natural gas processing plant site is exempt from the provisions of §§60.5400, 60.5401, 60.5402, 60.5421, and 60.5422 of this subpart.

(3) The equipment within a process unit of an affected facility located at onshore natural gas processing plants and described in paragraph (f) of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG or GGGa of this part.

(g) Sweetening units located at onshore natural gas processing plants that process natural gas produced from either onshore or offshore wells.

(1) Each sweetening unit that processes natural gas is an affected facility; and

(2) Each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility.

(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H₂S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in §60.5423(c) but are not required to comply with §§60.5405 through 60.5407 and §§60.5410(g) and 60.5415(g) of this subpart.

(4) Sweetening facilities producing acid gas that is completely reinjected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to §§60.5405 through 60.5407, 60.5410(g), 60.5415(g), and 60.5423 of this subpart.

(h) The following provisions apply to gas well facilities that are hydraulically refractured.

(1) A gas well facility that conducts a well completion operation following hydraulic fracturing is not an affected facility, provided that the requirements of §60.5375 are met. For purposes of this provision, the dates specified in §60.5375(a) do not apply, and such facilities, as of October 15, 2012, must meet the requirements of §60.5375(a)(1) through (4).

(2) A well completion operation following hydraulic fracturing at a gas well facility not conducted pursuant to §60.5375 is a modification to the gas well affected facility.

(3) Refracturing of a gas well facility does not affect the modification status of other equipment, process units, storage vessels, compressors, or pneumatic controllers located at the well site.

(4) A gas well facility initially constructed after August 23, 2011, and on or before September 18, 2015 is considered an affected facility regardless of this provision.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58435, Sept. 23, 2013; 79 FR 79036, Dec. 31, 2014; 80 FR 48268, Aug. 12, 2015; 81 FR 35896, June 3, 2016; 85 FR 57069, Sept. 14, 2020]

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§60.5370 When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than October 15, 2012 or upon startup, whichever is later.

(b) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

(d) You are deemed to be in compliance with this subpart if you are in compliance with all applicable provisions of subpart OOOOa of this part.

[77 FR 49542, Aug. 16, 2012, as amended at 81 FR 35896, June 3, 2016]

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§60.5375 What standards apply to gas well affected facilities?

If you are the owner or operator of a gas well affected facility, you must comply with paragraphs (a) through (f) of this section.

(a) Except as provided in paragraph (f) of this section, for each well completion operation with hydraulic fracturing begun prior to January 1, 2015, you must comply with the requirements of paragraphs (a)(3) and (4) of this section unless a more stringent state or local emission control requirement is applicable; optionally, you may comply with the requirements of paragraphs (a)(1) through (4) of this section. For each new well completion operation with hydraulic fracturing begun on or after January 1, 2015, you must comply with the requirements in paragraphs (a)(1) through (4) of this section. You must maintain a log as specified in paragraph (b).

(1) For each stage of the well completion operation, as defined in §60.5430, follow the requirements specified in paragraph (a)(1)(i) and (ii) of this section.

(i) During the initial flowback stage, route the flowback into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the initial flowback stage is not subject to control under this section.

(ii) During the separation flowback stage, route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the liquids into the well or another well or route the recovered liquids to a collection system. Route the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If it is infeasible to route the recovered gas as required above, follow the requirements in paragraph (a)(3) of this section. If, at any time during the

separation flowback stage, it is not technically feasible for a separator to function, you must comply with (a)(1)(i) of this section.

(2) All salable quality recovered gas must be routed to the gas flow line as soon as practicable. In cases where salable quality gas cannot be directed to the flow line, you must follow the requirements in paragraph (a)(3) of this section.

(3) You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source.

(4) You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

(b) You must maintain a log for each well completion operation at each gas well affected facility. The log must be completed on a daily basis for the duration of the well completion operation and must contain the records specified in §60.5420(c)(1)(iii).

(c) You must demonstrate initial compliance with the standards that apply to gas well affected facilities as required by §60.5410.

(d) You must demonstrate continuous compliance with the standards that apply to gas well affected facilities as required by §60.5415.

(e) You must perform the required notification, recordkeeping and reporting as required by §60.5420.

(f)(1) For each gas well affected facility specified in paragraphs (f)(1)(i) and (ii) of this section, you must comply with the requirements of paragraphs (f)(2) and (3) of this section.

(i) Each well completion operation with hydraulic fracturing at a wildcat or delineation well.

(ii) Each well completion operation with hydraulic fracturing at a non-wildcat low pressure gas well or non-delineation low pressure gas well.

(2) Route the flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the flowback before the separator can function is not subject to control under this section. You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source. You must also comply with paragraphs (a)(4) and (b) through (e) of this section.

(3) You must maintain records specified in §60.5420(c)(1)(iii) for wildcat, delineation and low pressure gas wells.

[77 FR 49542, Aug. 16, 2012, as amended at 79 FR 79037, Dec. 31, 2014]

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§60.5380 What standards apply to centrifugal compressor affected facilities?

You must comply with the standards in paragraphs (a) through (d) of this section for each centrifugal compressor affected facility.

(a)(1) You must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411(b), that is connected through a closed vent system that meets the requirements of §60.5411(a) and routed to a control device that meets the conditions specified in §60.5412(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(b) You must demonstrate initial compliance with the standards that apply to centrifugal compressor affected facilities as required by §60.5410(b).

(c) You must demonstrate continuous compliance with the standards that apply to centrifugal compressor affected facilities as required by §60.5415(b).

(d) You must perform the required notification, recordkeeping, and reporting as required by §60.5420.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58436, Sept. 23, 2013]

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§60.5385 What standards apply to reciprocating compressor affected facilities?

You must comply with the standards in paragraphs (a) through (d) of this section for each reciprocating compressor affected facility.

(a) You must replace the reciprocating compressor rod packing according to either paragraph (a)(1) or (2) of this section or you must comply with paragraph (a)(3) of this section.

(1) Before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, or October 15, 2012, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

(3) Collect the emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure and route the rod packing emissions to a process through a closed vent system that meets the requirements of §60.5411(a).

(b) You must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by §60.5410.

(c) You must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by §60.5415.

(d) You must perform the required notification, recordkeeping, and reporting as required by §60.5420.

[77 FR 49542, Aug. 16, 2012, as amended at 79 FR 79037, Dec. 31, 2014]

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§60.5390 What standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the VOC standards, based on natural gas as a surrogate for VOC, in either paragraph (b)(1) or (c)(1) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) of this section are exempt from this requirement.

(a) The requirements of paragraph (b)(1) or (c)(1) of this section are not required if you determine that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required based on functional needs, including but not limited to response time, safety and positive actuation. However, you must tag such pneumatic controller with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller, as required in §60.5420(c)(4)(ii).

(b)(1) Each pneumatic controller affected facility at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller as required in §60.5420(c)(4)(iv).

(c)(1) Each pneumatic controller affected facility constructed, modified or reconstructed on or after October 15, 2013, at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller affected facility constructed, modified or reconstructed on or after October 15, 2013, at a location between the wellhead and a natural gas processing plant or the point of custody transfer to an oil pipeline must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that controller as required in §60.5420(c)(4)(iii).

(d) You must demonstrate initial compliance with standards that apply to pneumatic controller affected facilities as required by §60.5410.

(e) You must demonstrate continuous compliance with standards that apply to pneumatic controller affected facilities as required by §60.5415.

(f) You must perform the required notification, recordkeeping, and reporting as required by §60.5420, except that you are not required to submit the notifications specified in §60.5420(a).

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§60.5395 What standards apply to storage vessel affected facilities?

Except as provided in paragraph (h) of this section, you must comply with the standards in this section for each storage vessel affected facility.

(a)(1) If you are the owner or operator of a Group 1 storage vessel affected facility, you must comply with paragraph (b) of this section.

(2) If you are the owner or operator of a Group 2 storage vessel affected facility, you must comply with paragraph (c) of this section.

(b) *Requirements for Group 1 storage vessel affected facilities.* If you are the owner or operator of a Group 1 storage vessel affected facility, you must comply with paragraphs (b)(1) and (2) of this section.

(1) You must submit a notification identifying each Group 1 storage vessel affected facility, including its location, with your initial annual report as specified in §60.5420(b)(6)(iv).

(2) You must comply with paragraphs (d) through (g) of this section.

(c) *Requirements for Group 2 storage vessel affected facilities.* If you are the owner or operator of a Group 2 storage vessel affected facility, you must comply with paragraphs (d) through (g) of this section.

(d) You must comply with the control requirements of paragraph (d)(1) of this section unless you meet the conditions specified in paragraph (d)(2) of this section.

(1) Reduce VOC emissions by 95.0 percent according to the schedule specified in (d)(1)(i) and (ii) of this section.

(i) For each Group 2 storage vessel affected facility, you must achieve the required emissions reductions by April 15, 2014, or within 60 days after startup, whichever is later, except as otherwise provided below in paragraph (f) of this section. For storage vessel affected facilities receiving liquids pursuant to the standards for gas well affected facilities in §60.5375, you must achieve the required emissions reductions within 60 days after startup of production as defined in §60.5430.

(ii) For each Group 1 storage vessel affected facility, you must achieve the required emissions reductions by April 15, 2015.

(2) Maintain the uncontrolled actual VOC emissions from the storage vessel affected facility at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology. Monthly calculations must be based on the average throughput for the month. Monthly calculations must be separated by at least 14 days. You must comply with

paragraph (d)(1) of this section if your storage vessel affected facility meets the conditions specified in paragraphs (d)(2)(i) or (ii) of this section.

(i) If a well feeding the storage vessel affected facility undergoes fracturing or refracturing, you must comply with paragraph (d)(1) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility.

(ii) If the monthly emissions determination required in this section indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, you must comply with paragraph (d)(1) of this section within 30 days of the monthly calculation.

(e) *Control requirements.* (1) Except as required in paragraph (e)(2) of this section, if you use a control device to reduce emissions from your storage vessel affected facility, you must equip the storage vessel with a cover that meets the requirements of §60.5411(b) and is connected through a closed vent system that meets the requirements of §60.5411(c), and you must route emissions to a control device that meets the conditions specified in §60.5412(c) and (d). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) If you use a floating roof to reduce emissions, you must meet the requirements of §60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

(f) *Requirements for Group 1 and Group 2 storage vessel affected facilities that are removed from service or returned to service.* If you remove a Group 1 or Group 2 storage vessel affected facility from service, you must comply with paragraphs (f)(1) through (3) of this section. A Group 1 or Group 2 storage vessel is not an affected facility under this subpart for the period that it is removed from service.

(1) For a storage vessel affected facility to be removed from service, you must comply with the requirements of paragraph (f)(1)(i) and (ii) of this section.

(i) You must completely empty and degas the storage vessel, such that the storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(ii) You must submit a notification as required in §60.5420(b)(6)(vi) in your next annual report, identifying each storage vessel affected facility removed from service during the reporting period and the date of its removal from service.

(2) If a storage vessel identified in paragraph (f)(1)(ii) of this section is returned to service, you must determine its affected facility status as provided in §60.5365(e).

(3) For each storage vessel affected facility returned to service during the reporting period, you must submit a notification in your next annual report as required in §60.5420(b)(6)(vii), identifying each storage vessel affected facility and the date of its return to service.

(g) *Compliance, notification, recordkeeping, and reporting.* You must comply with paragraphs (g)(1) through (3) of this section.

(1) You must demonstrate initial compliance with standards as required by §60.5410(h) and (i).

(2) You must demonstrate continuous compliance with standards as required by §60.5415(e)(3).

(3) You must perform the required notification, recordkeeping and reporting as required by §60.5420.

(h) *Exemptions.* This subpart does not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, 40 CFR part 63, subparts G, CC, HH, or WW.

[78 FR 58436, Sept. 23, 2013, as amended at 79 FR 79038, Dec. 31, 2014]

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§60.5400 What equipment leak standards apply to affected facilities at an onshore natural gas processing plant?

This section applies to the group of all equipment, except compressors, within a process unit.

(a) You must comply with the requirements of §§60.482-1a(a), (b), and (d), 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in §60.5401.

(b) You may elect to comply with the requirements of §§60.483-1a and 60.483-2a, as an alternative.

(c) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of §60.5402 of this subpart.

(d) You must comply with the provisions of §60.485a of this part except as provided in paragraph (f) of this section.

(e) You must comply with the provisions of §§60.486a and 60.487a of this part except as provided in §§60.5401, 60.5421, and 60.5422 of this part.

(f) You must use the following provision instead of §60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 (incorporated by reference as specified in §60.17) must be used.

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§60.5401 What are the exceptions to the equipment leak standards for affected facilities at onshore natural gas processing plants?

(a) You may comply with the following exceptions to the provisions of §60.5400(a) and (b).

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in §60.485a(b) except as provided in §60.5400(c) and in paragraph (b)(4) of this section, and §60.482-4a(a) through (c) of subpart VVa.

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9a.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within 5 days as specified in paragraph (b)(1) of this section and §60.482-4a(b)(1) of subpart VVa.

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section must be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of §60.482-5a.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§60.482-2a(a)(1), 60.482-7a(a), 60.482-11a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of §§60.482-2a(a)(1), 60.482-7a(a), 60.482-11a(a), and paragraph (b)(1) of this section.

(f) An owner or operator may use the following provisions instead of §60.485a(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °C (302 °F) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °C (302 °F) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

(g) An owner or operator may use the following provisions instead of §60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in §60.486a(e)(8). Divide these readings by the initial calibration values for each scale and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

[77 FR 49542, Aug. 16, 2012, as amended at 79 FR 79038, Dec. 31, 2014]

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§60.5402 What are the alternative emission limitations for equipment leaks from onshore natural gas processing plants?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the FEDERAL REGISTER, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

(d) The Administrator will treat applications under this section according to the following criteria, except in cases where the Administrator concludes that other criteria are appropriate:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.

(2) If the applicant is an owner or operator of an affected facility, the applicant must commit in writing to operate and maintain the alternative means so as to achieve a reduction in VOC emissions at least equivalent to the reduction in VOC emissions achieved under the design, equipment, work practice or operational standard.

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§60.5405 What standards apply to sweetening units at onshore natural gas processing plants?

(a) During the initial performance test required by §60.8(b), you must achieve at a minimum, an SO₂ emission reduction efficiency (Z_i) to be determined from Table 1 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an SO₂ emission reduction efficiency (Z_c) to be determined from Table 2 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

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§60.5406 What test methods and procedures must I use for my sweetening units affected facilities at onshore natural gas processing plants?

(a) In conducting the performance tests required in §60.8, you must use the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in paragraph §60.8(b).

(b) During a performance test required by §60.8, you must determine the minimum required reduction efficiencies (Z) of SO₂ emissions as required in §60.5405(a) and (b) as follows:

(1) The average sulfur feed rate (X) must be computed as follows:

$$X = KQ_aY$$

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Where:

X = average sulfur feed rate, Mg/D (LT/D).

Q_a = average volumetric flow rate of acid gas from sweetening unit, dscm/day (dscf/day).

Y = average H₂S concentration in acid gas feed from sweetening unit, percent by volume, expressed as a decimal.

K = (32 kg S/kg-mole)/((24.04 dscm/kg-mole)(1000 kg S/Mg)).

= 1.331 × 10⁻³ Mg/dscm, for metric units.

= (32 lb S/lb-mole)/((385.36 dscf/lb-mole)(2240 lb S/long ton)).

= 3.707 × 10⁻⁶ long ton/dscf, for English units.

(2) You must use the continuous readings from the process flowmeter to determine the average volumetric flow rate (Q_a) in dscm/day (dscf/day) of the acid gas from the sweetening unit for each run.

(3) You must use the Tutwiler procedure in §60.5408 or a chromatographic procedure following ASTM E260-96 (incorporated by reference as specified in §60.17) to determine the H₂S concentration in the acid gas feed from the sweetening unit (Y). At least one sample per hour (at equally spaced intervals) must be taken during each 4-hour run. The arithmetic mean of all samples must be the average H₂S concentration (Y) on a dry basis for the run. By multiplying the result from the Tutwiler procedure by 1.62 × 10⁻³, the units gr/100 scf are converted to volume percent.

(4) Using the information from paragraphs (b)(1) and (b)(3) of this section, Tables 1 and 2 of this subpart must be used to determine the required initial (Z_i) and continuous (Z_c) reduction efficiencies of SO_2 emissions.

(c) You must determine compliance with the SO_2 standards in §60.5405(a) or (b) as follows:

(1) You must compute the emission reduction efficiency (R) achieved by the sulfur recovery technology for each run using the following equation:

$$R = (100) \frac{E}{S + E}$$

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(2) You must use the level indicators or manual soundings to measure the liquid sulfur accumulation rate in the product storage vessels. You must use readings taken at the beginning and end of each run, the tank geometry, sulfur density at the storage temperature, and sample duration to determine the sulfur production rate (S) in kg/hr (lb/hr) for each run.

(3) You must compute the emission rate of sulfur for each run as follows:

$$E = \frac{C_e Q_{sd}}{K_1}$$

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Where:

E = emission rate of sulfur per run, kg/hr.

C_e = concentration of sulfur equivalent (SO_2 + reduced sulfur), g/dscm (lb/dscf).

Q_{sd} = volumetric flow rate of effluent gas, dscm/hr (dscf/hr).

K_1 = conversion factor, 1000 g/kg (7000 gr/lb).

(4) The concentration (C_e) of sulfur equivalent must be the sum of the SO_2 and TRS concentrations, after being converted to sulfur equivalents. For each run and each of the test methods specified in this paragraph (c) of this section, you must use a sampling time of at least 4 hours. You must use Method 1 of appendix A to part 60 of this chapter to select the sampling site. The sampling point in the duct must be at the centroid of the cross-section if the area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 in) if the cross-sectional area is 5 m^2 or more, and the centroid is more than 1 m (39 in.) from the wall.

(i) You must use Method 6 of appendix A to part 60 of this chapter to determine the SO_2 concentration. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration must be multiplied by 0.5×10^{-3} to convert the results to sulfur equivalent.

(ii) You must use Method 15 of appendix A to part 60 of this chapter to determine the TRS concentration from reduction-type devices or where the oxygen content of the effluent gas is less than 1.0 percent by volume. The sampling rate must be at least 3 liters/min (0.1 ft^3/min) to insure minimum residence time in the sample line. You must take sixteen samples at 15-minute intervals.

The arithmetic average of all the samples must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iii) You must use Method 16A or Method 15 of appendix A to part 60 of this chapter or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17) to determine the reduced sulfur concentration from oxidation-type devices or where the oxygen content of the effluent gas is greater than 1.0 percent by volume. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iv) You must use Method 2 of appendix A to part 60 of this chapter to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged. For the moisture content, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

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§60.5407 What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?

(a) If your sweetening unit affected facility is located at an onshore natural gas processing plant and is subject to the provisions of §60.5405(a) or (b) you must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the following operations information on a daily basis:

(1) *The accumulation of sulfur product over each 24-hour period.* The monitoring method may incorporate the use of an instrument to measure and record the liquid sulfur production rate, or may be a procedure for measuring and recording the sulfur liquid levels in the storage vessels with a level indicator or by manual soundings, with subsequent calculation of the sulfur production rate based on the tank geometry, stored sulfur density, and elapsed time between readings. The method must be designed to be accurate within ± 2 percent of the 24-hour sulfur accumulation.

(2) *The H_2S concentration in the acid gas from the sweetening unit for each 24-hour period.* At least one sample per 24-hour period must be collected and analyzed using the equation specified in §60.5406(b)(1). The Administrator may require you to demonstrate that the H_2S concentration obtained from one or more samples over a 24-hour period is within ± 20 percent of the average of 12 samples collected at equally spaced intervals during the 24-hour period. In instances where the H_2S concentration of a single sample is not within ± 20 percent of the average of the 12 equally spaced samples, the Administrator may require a more frequent sampling schedule.

(3) *The average acid gas flow rate from the sweetening unit.* You must install and operate a monitoring device to continuously measure the flow rate of acid gas. The monitoring device reading must be recorded at least once per hour during each 24-hour period. The average acid gas flow rate must be computed from the individual readings.

(4) *The sulfur feed rate (X).* For each 24-hour period, you must compute X using the equation specified in §60.5406(b)(1).

(5) *The required sulfur dioxide emission reduction efficiency for the 24-hour period.* You must use the sulfur feed rate and the H₂S concentration in the acid gas for the 24-hour period, as applicable, to determine the required reduction efficiency in accordance with the provisions of §60.5405(b).

(b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows:

(1) *A continuous monitoring system to measure the total sulfur emission rate (E) of SO₂ in the gases discharged to the atmosphere.* The SO₂ emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of §60.5405(b) will be between 30 percent and 70 percent of the measurement range of the instrument system.

(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with §60.5405(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ±1 percent of the temperature being measured.

(3) When performance tests are conducted under the provision of §60.8 to demonstrate compliance with the standards under §60.5405, the temperature of the gas leaving the incinerator combustion zone must be determined using the monitoring device. If the volumetric ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as SO₂) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate level determined during the most recent performance test to ensure the sulfur compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under §60.8.

(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds as required in paragraph (d) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).

(c) Where compliance is achieved through the use of a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as SO₂ equivalent in the gases discharged to the atmosphere. The SO₂ equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of §60.5405(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective

upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.

(d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock interval. The 24-hour interval may begin and end at any selected clock time, but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in §60.5406(c)(1).

(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S.

(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average.

(e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of H₂S expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:

$$R = \frac{K_2 S}{X}$$

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Where:

R = The sulfur dioxide removal efficiency achieved during the 24-hour period, percent.

K₂ = Conversion factor, 0.02400 Mg/D per kg/hr (0.01071 LT/D per lb/hr).

S = The sulfur production rate during the 24-hour period, kg/hr (lb/hr).

X = The sulfur feed rate in the acid gas, Mg/D (LT/D).

(f) The monitoring devices required in paragraphs (b)(1), (b)(3) and (c) of this section must be calibrated at least annually according to the manufacturer's specifications, as required by §60.13(b).

(g) The continuous emission monitoring systems required in paragraphs (b)(1), (b)(3), and (c) of this section must be subject to the emission monitoring requirements of §60.13 of the General Provisions. For conducting the continuous emission monitoring system performance evaluation required by §60.13(c), Performance Specification 2 of appendix B to part 60 of this chapter must apply, and Method 6 must be used for systems required by paragraph (b) of this section.

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§60.5408 What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?

The Tutwiler procedure may be found in the Gas Engineers Handbook, Fuel Gas Engineering practices, The Industrial Press, 93 Worth Street, New York, NY, 1966, First Edition, Second Printing, page 6/25 (Docket A-80-20-A, Entry II-I-67).

(a) When an instantaneous sample is desired and H_2S concentration is ten grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than ten grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine.

(b) *Apparatus.* (See Figure 1 of this subpart) A 100 or 500 ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top which connect either with inlet tubulature or glass-stoppered cylinder, 10 ml capacity, graduated in 0.1 ml subdivision; rubber tubing connecting burette with leveling bottle.

(c) *Reagents.* (1) Iodine stock solution, 0.1N. Weight 12.7 g iodine, and 20 to 25 g cp potassium iodide for each liter of solution. Dissolve KI in as little water as necessary; dissolve iodine in concentrated KI solution, make up to proper volume, and store in glass-stoppered brown glass bottle.

(2) Standard iodine solution, 1 ml = 0.001771 g I. Transfer 33.7 ml of above 0.1N stock solution into a 250 ml volumetric flask; add water to mark and mix well. Then, for 100 ml sample of gas, 1 ml of standard iodine solution is equivalent to 100 grains H_2S per cubic feet of gas.

(3) Starch solution. Rub into a thin paste about one teaspoonful of wheat starch with a little water; pour into about a pint of boiling water; stir; let cool and decant off clear solution. Make fresh solution every few days.

(d) *Procedure.* Fill leveling bulb with starch solution. Raise (L), open cock (G), open (F) to (A), and close (F) when solutions starts to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine thru (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D.

(e) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then, Grains H_2S per 100 cubic foot of gas = $100(D-C)$

(f) Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with H_2S -free gas or air, is required.

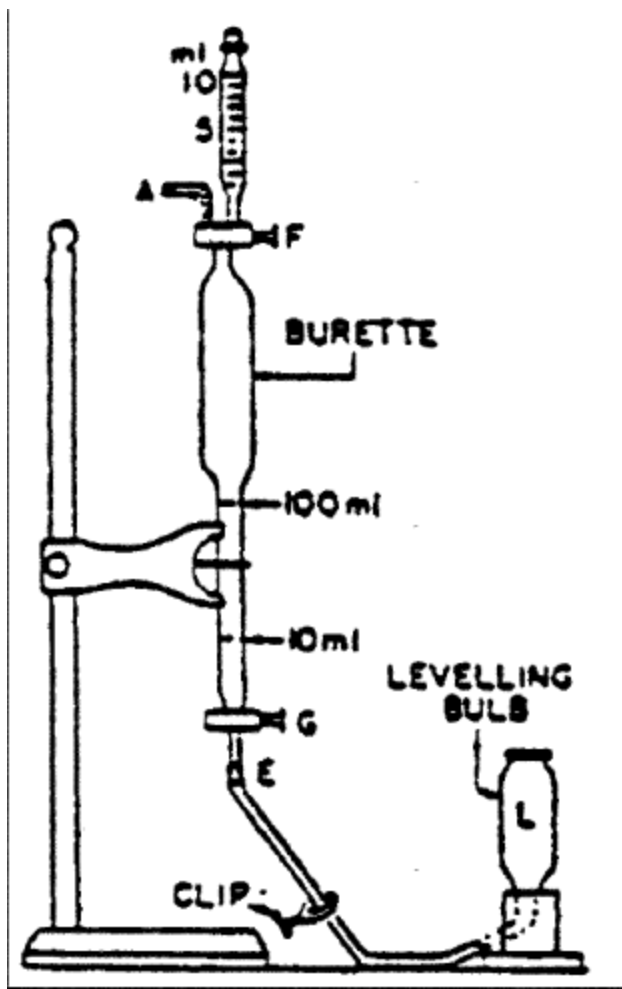


Figure 1. Tutwiler burette (lettered items mentioned in text).

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§60.5410 How do I demonstrate initial compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (i) of this section. The initial compliance period begins on October 15, 2012, or upon initial startup, whichever is later, and ends no later than one year after the initial startup date for your affected facility or no later than one year after October 15, 2012. The initial compliance period may be less than one full year.

(a) To achieve initial compliance with the standards for each well completion operation conducted at your gas well affected facility you must comply with paragraphs (a)(1) through (a)(4) of this section.

(1) You must submit the notification required in §60.5420(a)(2).

(2) You must submit the initial annual report for your well affected facility as required in §60.5420(b).

(3) You must maintain a log of records as specified in §60.5420(c)(1)(i) through (iv) for each well completion operation conducted during the initial compliance period.

(4) For each gas well affected facility subject to both §60.5375(a)(1) and (3), as an alternative to retaining the records specified in §60.5420(c)(1)(i) through (iv), you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each gas well completion operation that occurred during the initial compliance period. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment connected and operating at each well completion operation with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

(b)(1) To achieve initial compliance with standards for your centrifugal compressor affected facility you must reduce VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater as required by §60.5380 and as demonstrated by the requirements of §60.5413.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411(b) that is connected through a closed vent system that meets the requirements of §60.5411(a) and is routed to a control device that meets the conditions specified in §60.5412(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(3) You must conduct an initial performance test as required in §60.5413 within 180 days after initial startup or by October 15, 2012, whichever is later, and you must comply with the continuous compliance requirements in §60.5415(b)(1) through (3).

(4) You must conduct the initial inspections required in §60.5416(a) and (b).

(5) You must install and operate the continuous parameter monitoring systems in accordance with §60.5417(a) through (g), as applicable.

(6) [Reserved]

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in §60.5420(b)(3) for each centrifugal compressor affected facility.

(8) You must maintain the records as specified in §60.5420(c)(2).

(c) To achieve initial compliance with the standards for each reciprocating compressor affected facility you must comply with paragraphs (c)(1) through (4) of this section.

(1) If complying with §60.5385(a)(1) or (2), during the initial compliance period, you must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement.

(2) If complying with §60.5385(a)(3), you must operate the rod packing emissions collection system under negative pressure and route emissions to a process through a closed vent system that meets the requirements of §60.5411(a).

(3) You must submit the initial annual report for your reciprocating compressor as required in §60.5420(b).

(4) You must maintain the records as specified in §60.5420(c)(3) for each reciprocating compressor affected facility.

(d) To achieve initial compliance with emission standards for your pneumatic controller affected facility you must comply with the requirements specified in paragraphs (d)(1) through (6) of this section, as applicable.

(1) You must demonstrate initial compliance by maintaining records as specified in §60.5420(c)(4)(ii) of your determination that the use of a pneumatic controller affected facility with a bleed rate greater than 6 standard cubic feet of gas per hour is required as specified in §60.5390(a).

(2) You own or operate a pneumatic controller affected facility located at a natural gas processing plant and your pneumatic controller is driven by a gas other than natural gas and therefore emits zero natural gas.

(3) You own or operate a pneumatic controller affected facility located between the wellhead and a natural gas processing plant and the manufacturer's design specifications indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.

(4) You must tag each new pneumatic controller affected facility according to the requirements of §60.5390(b)(2) or (c)(2).

(5) You must include the information in paragraph (d)(1) of this section and a listing of the pneumatic controller affected facilities specified in paragraphs (d)(2) and (3) of this section in the initial annual report submitted for your pneumatic controller affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of §60.5420(b).

(6) You must maintain the records as specified in §60.5420(c)(4) for each pneumatic controller affected facility.

(e) [Reserved]

(f) For affected facilities at onshore natural gas processing plants, initial compliance with the VOC requirements is demonstrated if you are in compliance with the requirements of §60.5400.

(g) For sweetening unit affected facilities at onshore natural gas processing plants, initial compliance is demonstrated according to paragraphs (g)(1) through (3) of this section.

(1) To determine compliance with the standards for SO₂ specified in §60.5405(a), during the initial performance test as required by §60.8, the minimum required sulfur dioxide emission reduction efficiency (Z_i) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology as specified in paragraphs (g)(1)(i) and (ii) of this section.

(i) If $R \geq Z_i$, your affected facility is in compliance.

(ii) If $R < Z_i$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in §60.5406(c)(1).

(3) You have submitted the results of paragraphs (g)(1) and (2) of this section in the initial annual report submitted for your sweetening unit affected facilities at onshore natural gas processing plants.

(h) For each storage vessel affected facility, you must comply with paragraphs (h)(1) through (5) of this section. For a Group 1 storage vessel affected facility, you must demonstrate initial compliance by April 15, 2015, except as otherwise provided in paragraph (i) of this section. For a Group 2 storage vessel affected facility, you must demonstrate initial compliance by April 15, 2014, or within 60 days after startup, whichever is later.

(1) You must determine the potential VOC emission rate as specified in §60.5365(e).

(2) You must reduce VOC emissions in accordance with §60.5395(d).

(3) If you use a control device to reduce emissions, or if you route emissions to a process, you must demonstrate initial compliance by meeting the requirements in §60.5395(e).

(4) You must submit the information required for your storage vessel affected facility as specified in §60.5420(b).

(5) You must maintain the records required for your storage vessel affected facility, as specified in §60.5420(c)(5) through (8) and §60.5420(c)(12) and (13) for each storage vessel affected facility.

(i) For each Group 1 storage vessel affected facility, you must submit the notification specified in §60.5395(b)(2) with the initial annual report specified in §60.5420(b)(6).

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58437, Sept. 23, 2013; 79 FR 79038, Dec. 31, 2014; 81 FR 35896, June 3, 2016]

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§60.5411 What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing materials from storage vessels, reciprocating compressors and centrifugal compressor wet seal degassing systems?

You must meet the applicable requirements of this section for each cover and closed vent system used to comply with the emission standards for your storage vessel, reciprocating compressor or centrifugal compressor affected facility.

(a) Closed vent system requirements for reciprocating compressors and for centrifugal compressor wet seal degassing systems. (1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the reciprocating compressor rod packing emissions collection system or the wet seal fluid degassing system to a control device or to a process that meets the requirements specified in §60.5412(a) through (c).

(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by §60.5416(b).

(3) You must meet the requirements specified in paragraphs (a)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device.

(i) Except as provided in paragraph (a)(3)(ii) of this section, you must comply with either paragraph (a)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings as specified in §60.5416(a)(4) and either sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (a)(3)(i) of this section.

(b) Cover requirements for storage vessels and centrifugal compressor wet seal degassing systems. (1) The cover and all openings on the cover (e.g., access hatches, sampling ports, pressure relief valves and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or wet seal fluid degassing system.

(2) Each cover opening shall be secured in a closed, sealed position (e.g., covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed-vent system designed and operated in accordance with the requirements of paragraph (a) or (c) of this section to a control device or to a process.

(3) Each storage vessel thief hatch shall be equipped, maintained and operated with a weighted mechanism or equivalent, to ensure that the lid remains properly seated. You must select gasket material for the hatch based on composition of the fluid in the storage vessel and weather conditions.

(c) Closed vent system requirements for storage vessel affected facilities using a control device or routing emissions to a process. (1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the storage vessel to a control device that meets the requirements specified in §60.5412(c) and (d), or to a process.

(2) You must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual and auditory inspections. Each closed vent system that routes emissions to a process must be operational 95 percent of the year or greater.

(3) You must meet the requirements specified in paragraphs (c)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process.

(i) Except as provided in paragraph (c)(3)(ii) of this section, you must comply with either paragraph (c)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere and that either sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (c)(3)(i) of this section.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58438, Sept. 23, 2013; 79 FR 79038, Dec. 31, 2014; 81 FR 35896, June 3, 2016]

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§60.5412 What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my storage vessel or centrifugal compressor affected facility?

You must meet the applicable requirements of this section for each control device used to comply with the emission standards for your storage vessel or centrifugal compressor affected facility.

(a) Each control device used to meet the emission reduction standard in §60.5380(a)(1) for your centrifugal compressor affected facility must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a control device model tested under §60.5413(d), which meets the criteria in §60.5413(d)(11) and §60.5413(e).

(1) Each combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section.

(i) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413.

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the requirements of §60.5413.

(iii) You must operate at a minimum temperature of 760 °C for a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under §60.5413.

(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(2) Each vapor recovery device (e.g., carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413. As an alternative to the performance testing requirements, you may demonstrate initial compliance by conducting a design analysis for vapor recovery devices according to the requirements of §60.5413(c).

(3) You must design and operate a flare in accordance with the requirements of §60.5413.

(b) You must operate each control device installed on your centrifugal compressor affected facility in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system affected facility, as required under §60.5380(a), through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

(2) For each control device monitored in accordance with the requirements of §60.5417(a) through (g), you must demonstrate compliance according to the requirements of §60.5415(b)(2), as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) or (d)(2) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (c)(1) or (2) of this section.

(1) Following the initial startup of the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to §60.5413(c)(2) or (3) or according to the design required in paragraph (d)(2) of this section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in §60.5420(c)(10) and (12).

(2) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(2)(i) through (vii) of this section.

(i) Regenerate or reactivate the spent carbon in a thermal treatment unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(ii) Regenerate or reactivate the spent carbon in a thermal treatment unit equipped with and operating air emission controls in accordance with this section.

(iii) Regenerate or reactivate the spent carbon in a thermal treatment unit equipped with and operating organic air emission controls in accordance with an emissions standard for VOC under another subpart in 40 CFR part 60 or this part.

(iv) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart O.

(v) Burn the spent carbon in a hazardous waste incinerator which you have designed and operated in accordance with the requirements of 40 CFR part 265, subpart O.

(vi) Burn the spent carbon in a boiler or industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(vii) Burn the spent carbon in a boiler or industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(d) Each control device used to meet the emission reduction standard in §60.5395(d) for your storage vessel affected facility must be installed according to paragraphs (d)(1) through (3) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a control device model tested under §60.5413(d), which meets the criteria in §60.5413(d)(11) and §60.5413(e).

(1) Each enclosed combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed to reduce the mass content of VOC emissions by 95.0 percent or greater. Each flare must be designed and operated in accordance with the requirements of §60.5413(a)(1). You must follow the requirements in paragraphs (d)(1)(i) through (iv) of this section.

(i) Ensure that each enclosed combustion device is maintained in a leak free condition.

(ii) Install and operate a continuous burning pilot flame.

(iii) Operate the enclosed combustion device with no visible emissions, except for periods not to exceed a total of one minute during any 15 minute period. A visible emissions test using section 11 of EPA Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes. Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for

inspection. Following return to operation from maintenance or repair activity, each device must pass a Method 22, 40 CFR part 60, appendix A, visual observation as described in this paragraph.

(iv) Each enclosed combustion control device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (d)(1)(iv)(A) through (D) of this section.

(A) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413.

(B) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the requirements of §60.5413.

(C) You must operate at a minimum temperature of 760 °Celsius, provided the control device has demonstrated, during the performance test conducted under §60.5413, that combustion zone temperature is an indicator of destruction efficiency.

(D) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(2) Each vapor recovery device (e.g., carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater. A carbon replacement schedule must be included in the design of the carbon adsorption system.

(3) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58438, Sept. 23, 2013; 79 FR 79039, Dec. 31, 2014; 81 FR 35897, June 3, 2016]

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§60.5413 What are the performance testing procedures for control devices used to demonstrate compliance at my storage vessel or centrifugal compressor affected facility?

This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your centrifugal compressor affected facility. You must demonstrate that a control device achieves the performance requirements of §60.5412(a) using the performance test methods and procedures specified in this section. For condensers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section. In addition, this section contains the requirements for enclosed combustion device performance tests conducted by the manufacturer applicable to both storage vessel and centrifugal compressor affected facilities.

(a) *Performance test exemptions.* You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.

(1) A flare that is designed and operated in accordance with §60.18(b). You must conduct the compliance determination using Method 22 at 40 CFR part 60, appendix A-7, to determine visible emissions.

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have either been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; or you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H.

(5) A hazardous waste incinerator for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 264, subpart O; or you have certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

(6) A performance test is waived in accordance with §60.8(b).

(7) A control device whose model can be demonstrated to meet the performance requirements of §60.5412(a) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) *Test methods and procedures.* You must use the test methods and procedures specified in paragraphs (b)(1) through (5) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of §60.5412(a). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) of this section.

(1) You must use Method 1 or 1A at 40 CFR part 60, appendix A-1, as appropriate, to select the sampling sites specified in paragraphs (b)(1)(i) and (ii) of this section. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(i) Sampling sites must be located at the inlet of the first control device, and at the outlet of the final control device, to determine compliance with the control device percent reduction requirement specified in §60.5412(a)(1)(i) or (a)(2).

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with the enclosed combustion device total TOC concentration limit specified in §60.5412(a)(1)(ii).

(2) You must determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D at 40 CFR part 60, appendix A-2, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in §60.5412(a)(1)(i) or (a)(2), you must use Method 25A at 40 CFR part 60, appendix A-7. You must use the procedures in paragraphs (b)(3)(i) through (iv) of this section to calculate percent reduction efficiency.

(i) For each run, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(ii) You must compute the mass rate of TOC (minus methane and ethane) using the equations and procedures specified in paragraphs (b)(3)(ii)(A) and (B) of this section.

(A) You must use the following equations:

$$E_i = K_2 \left(\sum_{j=1}^n C_{ij} M_{ij} \right) Q_i$$

$$E_o = K_2 \left(\sum_{j=1}^n C_{oj} M_{oj} \right) Q_o$$

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Where:

E_i , E_o = Mass rate of TOC (minus methane and ethane) at the inlet and outlet of the control device, respectively, dry basis, kilogram per hour.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 °C.

C_i , C_o = Concentration of sample component j of the gas stream at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M_i , M_o = Molecular weight of sample component j of the gas stream at the inlet and outlet of the control device, respectively, gram/gram-mole.

Q_i , Q_o = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

n = Number of components in sample.

(B) When calculating the TOC mass rate, you must sum all organic compounds (minus methane and ethane) measured by Method 25A at 40 CFR part 60, appendix A-7 using the equations in paragraph (b)(3)(ii)(A) of this section.

(iii) You must calculate the percent reduction in TOC (minus methane and ethane) as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} \times 100\%$$

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Where:

R_{cd} = Control efficiency of control device, percent.

E_i = Mass rate of TOC (minus methane and ethane) at the inlet to the control device as calculated under paragraph (b)(3)(ii) of this section, kilograms TOC per hour or kilograms HAP per hour.

E_o = Mass rate of TOC (minus methane and ethane) at the outlet of the control device, as calculated under paragraph (b)(3)(ii) of this section, kilograms TOC per hour per hour.

(iv) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC (minus methane and ethane) across the device by comparing the TOC (minus methane and ethane) in all combusted vent streams and primary and secondary fuels with the TOC (minus methane and ethane) exiting the device, respectively.

(4) You must use Method 25A at 40 CFR part 60, appendix A-7 to measure TOC (minus methane and ethane) to determine compliance with the enclosed combustion device total VOC concentration limit specified in §60.5412(a)(1)(ii). You must calculate parts per million by volume concentration and correct to 3 percent oxygen, using the procedures in paragraphs (b)(4)(i) through (iii) of this section.

(i) For each run, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(ii) You must calculate the TOC concentration for each run as follows:

$$C_{TOC} = \sum_{i=1}^x \frac{(\sum_{j=1}^n C_{ji})}{x}$$

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Where:

C_{TOC} = Concentration of total organic compounds minus methane and ethane, dry basis, parts per million by volume.

C_{ji} = Concentration of sample component j of sample i, dry basis, parts per million by volume.

n = Number of components in the sample.

x = Number of samples in the sample run.

(iii) You must correct the TOC concentration to 3 percent oxygen as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B at 40 CFR part 60, appendix A, ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration.

(B) You must correct the TOC concentration for percent oxygen as follows:

$$C_c = C_m \left(\frac{17.9}{20.9 - \%O_{2d}} \right)$$

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Where:

C_c = TOC concentration corrected to 3 percent oxygen, dry basis, parts per million by volume.

C_m = TOC concentration, dry basis, parts per million by volume.

%O_{2d} = Concentration of oxygen, dry basis, percent by volume.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after initial startup for your affected facility. You must submit the performance test results as required in §60.5420(b)(7).

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests except as specified in paragraphs (b)(5)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in §60.5420(b)(7). Combustion control devices meeting the criteria in either paragraph (b)(5)(ii)(A) or (B) of this section are not required to conduct periodic performance tests.

(A) A control device whose model is tested under, and meets the criteria of paragraph (d) of this section.

(B) A combustion control device tested under paragraph (b) of this section that meets the outlet TOC performance level specified in §60.5412(a)(1)(ii) and that establishes a correlation between firebox or combustion chamber temperature and the TOC performance level.

(c) *Control device design analysis to meet the requirements of §60.5412(a).* (1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and must establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon used for the carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems will incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the Administrator do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the

requirements of paragraph (b) of this section to resolve the disagreement. The Administrator may choose to have an authorized representative observe the performance test.

(d) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer must demonstrate that a specific model of control device achieves the performance requirements in paragraph (d)(11) of this section by conducting a performance test as specified in paragraphs (d)(2) through (10) of this section. You must submit a test report for each combustion control device in accordance with the requirements in paragraph (d)(12) of this section.

(2) Performance testing must consist of three one-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. Propene (propylene) gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90-100 percent of maximum design rate (fixed rate).

(ii) 70-100-70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30-70-30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0-30-0 percent (ramp up, ramp down). Begin the test at the minimum firing rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to the minimum firing rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures must be tested simultaneously and with all burners operational. Results must be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System. A graphic presentation or strip chart of the control device operating data and emissions test data must be included in the test report in accordance with paragraph (d)(12) of this section. Inlet fuel meter data may be manually recorded provided that all inlet fuel data readings are included in the final report.

(4) Inlet testing must be conducted as specified in paragraphs (d)(4)(i) through (ii) of this section.

(i) The inlet gas flow metering system must be located in accordance with Method 2A, 40 CFR part 60, appendix A-1, (or other approved procedure) to measure inlet gas flow rate at the control device inlet location. You must position the fitting for filling fuel sample containers a minimum of eight pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet flow rate must be determined using Method 2A, 40 CFR part 60, appendix A-1. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute test.

(5) Inlet gas sampling must be conducted as specified in paragraphs (d)(5)(i) through (ii) of this section.

(i) At the inlet gas sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3-hour period. Filling must be conducted as specified in paragraphs (d)(5)(i)(A) through (C) of this section.

(A) Open the canister sampling valve at the beginning of each test run, and close the canister at the end of each test run.

(B) Fill one canister across the three test runs such that one composite fuel sample exists for each test condition.

(C) Label the canisters individually and record sample information on a chain of custody form.

(ii) Analyze each inlet gas sample using the methods in paragraphs (d)(5)(ii)(A) through (C) of this section. You must include the results in the test report required by paragraph (d)(12) of this section.

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945-03.

(B) Hydrogen (H₂), carbon monoxide (CO), carbon dioxide (CO₂), nitrogen (N₂), oxygen (O₂) using ASTM D1945-03.

(C) Higher heating value using ASTM D3588-98 or ASTM D4891-89.

(6) Outlet testing must be conducted in accordance with the criteria in paragraphs (d)(6)(i) through (v) of this section.

(i) Sample and flow rate must be measured in accordance with paragraphs (d)(6)(i)(A) through (B) of this section.

(A) The outlet sampling location must be a minimum of four equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports must be used.

(B) Flow rate must be measured using Method 1, 40 CFR part 60, appendix A-1 for determining flow measurement traverse point location, and Method 2, 40 CFR part 60, appendix A-1 for measuring duct velocity. If low flow conditions are encountered (*i.e.*, velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer must be used to obtain an accurate flow profile.

(ii) Molecular weight and excess air must be determined as specified in paragraph (d)(7) of this section.

(iii) Carbon monoxide must be determined as specified in paragraph (d)(8) of this section.

(iv) THC must be determined as specified in paragraph (d)(9) of this section.

(v) Visible emissions must be determined as specified in paragraph (d)(10) of this section.

(7) Molecular weight and excess air determination must be performed as specified in paragraphs (d)(7)(i) through (iii) of this section.

(i) An integrated bag sample must be collected during the Method 4, 40 CFR part 60, appendix A-3, moisture test following the procedure specified in (d)(7)(i)(A) through (B) of this section. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC-TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(C) through (D) of this section.

(A) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(B) Purge the sampling line with stack gas before opening the valve and beginning to fill the bag. Clearly label each bag and record sample information on a chain of custody form.

(C) The bag contents must be vigorously mixed prior to the gas chromatograph analysis.

(D) The GC-TCD calibration procedure in Method 3C, 40 CFR part 60, appendix A, must be modified by using EPA Alt-045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, repeat the initial calibration using at least three concentration levels.

(ii) Calculate and report the molecular weight of oxygen, carbon dioxide, methane, and nitrogen in the integrated bag sample and include in the test report specified in paragraph (d)(12) of this section. Moisture must be determined using Method 4, 40 CFR part 60, appendix A-3. Traverse both ports with the Method 4, 40 CFR part 60, appendix A-3, sampling train during each test run. Ambient air must not be introduced into the Method 3C, 40 CFR part 60, appendix A-2, integrated bag sample during the port change.

(iii) Excess air must be determined using resultant data from the EPA Method 3C tests and EPA Method 3B, 40 CFR part 60, appendix A, equation 3B-1.

(8) Carbon monoxide must be determined using Method 10, 40 CFR part 60, appendix A. Run the test simultaneously with Method 25A, 40 CFR part 60, appendix A-7 using the same sampling points. An instrument range of 0-10 parts per million by volume-dry (ppmvd) is recommended.

(9) Total hydrocarbon determination must be performed as specified by in paragraphs (d)(9)(i) through (vii) of this section.

(i) Conduct THC sampling using Method 25A, 40 CFR part 60, appendix A-7, except that the option for locating the probe in the center 10 percent of the stack is not allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during each test run.

(ii) A valid test must consist of three Method 25A, 40 CFR part 60, appendix A-7, tests, each no less than 60 minutes in duration.

(iii) A 0-10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0-30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases must be propane in air and be certified through EPA Protocol 1—"EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," (incorporated by reference as specified in §60.17).

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent CO₂, as measured by Method 3C, 40 CFR part 60, appendix A-2. You must use the following equation for this diluent concentration correction:

$$C_{\text{corr}} = C_{\text{meas}} \left(\frac{3}{\text{CO}_{2\text{meas}}} \right)$$

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Where:

C_{meas} = The measured concentration of the pollutant.

CO_{2meas} = The measured concentration of the CO₂ diluent.

3 = The corrected reference concentration of CO₂ diluent.

C_{corr} = The corrected concentration of the pollutant.

(vii) Subtraction of methane or ethane from the THC data is not allowed in determining results.

(10) Visible emissions must be determined using Method 22, 40 CFR part 60, appendix A. The test must be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, must be taken once per test run and the 12 photos included in the test report specified in paragraph (d)(12) of this section.

(11) *Performance test criteria.* (i) The control device model tested must meet the criteria in paragraphs (d)(11)(i)(A) through (D) of this section. These criteria must be reported in the test report required by paragraph (d)(12) of this section.

(A) Method 22, 40 CFR part 60, appendix A, results under paragraph (d)(10) of this section with no indication of visible emissions.

(B) Average Method 25A, 40 CFR part 60, appendix A, results under paragraph (d)(9) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO₂.

(C) Average CO emissions determined under paragraph (d)(8) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO₂.

(D) Excess combustion air determined under paragraph (d)(7) of this section equal to or greater than 150 percent.

(ii) The manufacturer must determine a maximum inlet gas flow rate which must not be exceeded for each control device model to achieve the criteria in paragraph (d)(11)(iii) of this section. The maximum inlet gas flow rate must be included in the test report required by paragraph (d)(12) of this section.

(iii) A control device meeting the criteria in paragraph (d)(11)(i)(A) through (D) of this section must demonstrate a destruction efficiency of 95 percent for VOC regulated under this subpart.

(12) The owner or operator of a combustion control device model tested under this paragraph must submit the information listed in paragraphs (d)(12)(i) through (vi) in the test report required by this section in accordance with §60.5420(b)(8).

(i) A full schematic of the control device and dimensions of the device components.

(ii) The maximum net heating value of the device.

(iii) The test fuel gas flow range (in both mass and volume). Include the maximum allowable inlet gas flow rate.

(iv) The air/stream injection/assist ranges, if used.

(v) The test conditions listed in paragraphs (d)(12)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess combustion air range.

(G) Flame arrestor(s).

(H) Burner manifold.

(I) Pilot flame indicator.

(J) Pilot flame design fuel and calculated or measured fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, strip charts, or other graphic presentations of the data annotated with test times and calibration values.

(e) Continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section. This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (d) of this section. Owners or operators must demonstrate that a control device achieves the performance requirements in (d)(11) of this section by installing a device tested under paragraph (d) of this section and complying with the criteria specified in paragraphs (e)(1) through (7) of this section.

(1) The inlet gas flow rate must be equal to or less than the maximum specified by the manufacturer.

(2) A pilot flame must be present at all times of operation.

(3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(4) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(5) Following return to operation from maintenance or repair activity, each device must pass an EPA Method 22, 40 CFR part 60, appendix A, visual observation as described in paragraph (e)(3) of this section.

(6) If the owner or operator operates a combustion control device model tested under this section, an electronic copy of the performance test results required by this section shall be submitted via email to *Oil____and____Gas____PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/*.

(7) Ensure that each enclosed combustion device is maintained in a leak free condition.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58439, Sept. 23, 2013; 79 FR 79039, Dec. 31, 2014; 81 FR 35897, June 3, 2016]

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§60.5415 How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?

(a) For each gas well affected facility, you must demonstrate continuous compliance by submitting the reports required by §60.5420(b) and maintaining the records for each completion operation specified in §60.5420(c)(1).

(b) For each centrifugal compressor affected facility, you must demonstrate continuous compliance according to paragraphs (b)(1) through (3) of this section.

(1) You must reduce VOC emissions from the wet seal fluid degassing system by 95.0 percent or greater.

(2) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of §60.5412(a) using the procedures specified in paragraphs (b)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in §60.5412(a)(2), you must demonstrate compliance according to paragraph (b)(2)(viii) of this section. You may switch between compliance with paragraphs (b)(2)(i) through (vii) of this section and compliance with paragraph (b)(2)(viii) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next annual report, as required in §60.5420(b), following the change.

(i) You must operate below (or above) the site specific maximum (or minimum) parameter value established according to the requirements of §60.5417(f)(1).

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with §60.5417(e) except that the inlet gas flow rate to the control device must not be averaged.

(iii) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (b)(2)(ii) of this section is either equal to or greater than the minimum monitoring value or equal to or less than the maximum monitoring value established under paragraph (b)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in §60.5413(d), compliance with the operating parameter limit is achieved when the criteria in §60.5413(e) are met.

(iv) You must operate the continuous monitoring system required in §60.5417 at all times the affected source is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments). A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(v) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data

collected during all other required data collection periods to assess the operation of the control device and associated control system.

(vi) Failure to collect required data is a deviation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments).

(vii) If you use a combustion control device to meet the requirements of §60.5412(a) and you demonstrate compliance using the test procedures specified in §60.5413(b), you must comply with paragraphs (b)(2)(vii)(A) through (D) of this section.

(A) A pilot flame must be present at all times of operation.

(B) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(C) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(D) Following return to operation from maintenance or repair activity, each device must pass a Method 22, 40 CFR part 60, appendix A, visual observation as described in paragraph (b)(2)(vii)(B) of this section.

(viii) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in §60.5412(a)(2), you must demonstrate compliance using the procedures in paragraphs (b)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to §60.5417(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with §60.5417(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (b)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (b)(2)(viii)(A) of this section.

(D) Except as provided in paragraphs (b)(2)(viii)(D)(1) and (2) of this section, at the end of each operating day, you must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (b)(2)(viii)(C) of this section.

(1) After the compliance dates specified in §60.5370, if you have less than 120 days of data for determining average TOC emission reduction, you must calculate the average TOC emission reduction for the first 120 days of operation after the compliance dates. You have demonstrated

compliance with the overall 95.0 percent reduction requirement if the 120-day average TOC emission reduction is equal to or greater than 95.0 percent.

(2) After 120 days and no more than 364 days of operation after the compliance date specified in §60.5370, you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days between the current day and the applicable compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement, if the average TOC emission reduction is equal to or greater than 95.0 percent.

(E) If you have data for 365 days or more of operation, you have demonstrated compliance with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in paragraph (b)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

(3) You must submit the annual report required by 60.5420(b) and maintain the records as specified in §60.5420(c)(2).

(c) For each reciprocating compressor affected facility complying with §60.5385(a)(1) or (2), you must demonstrate continuous compliance according to paragraphs (c)(1) through (3) of this section. For each reciprocating compressor affected facility complying with §60.5385(a)(3), you must demonstrate continuous compliance according to paragraph (c)(4) of this section.

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor affected facility or track the number of months since initial startup, or October 15, 2012, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) You must submit the annual report as required in §60.5420(b) and maintain records as required in §60.5420(c)(3).

(3) You must replace the reciprocating compressor rod packing before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

(4) You must operate the rod packing emissions collection system under negative pressure and continuously comply with the closed vent requirements in §60.5416(a) and (b).

(d) For each pneumatic controller affected facility, you must demonstrate continuous compliance according to paragraphs (d)(1) through (3) of this section.

(1) You must continuously operate the pneumatic controllers as required in §60.5390(a), (b), or (c).

(2) You must submit the annual report as required in §60.5420(b).

(3) You must maintain records as required in §60.5420(c)(4).

(e) You must demonstrate continuous compliance according to paragraph (e)(3) of this section for each storage vessel affected facility, for which you are using a control device or routing emissions to a process to meet the requirement of §60.5395(d)(1).

(1)-(2) [Reserved]

(3) For each storage vessel affected facility, you must comply with paragraphs (e)(3)(i) and (ii) of this section.

(i) You must reduce VOC emissions as specified in §60.5395(d).

(ii) For each control device installed to meet the requirements of §60.5395(d), you must demonstrate continuous compliance with the performance requirements of §60.5412(d) for each storage vessel affected facility using the procedure specified in paragraph (e)(3)(ii)(A) and either (e)(3)(ii)(B) or (e)(3)(ii)(C) of this section.

(A) You must comply with §60.5416(c) for each cover and closed vent system.

(B) You must comply with §60.5417(h) for each control device.

(C) Each closed vent system that routes emissions to a process must be operated as specified in §60.5411(c)(2).

(f) For affected facilities at onshore natural gas processing plants, continuous compliance with VOC requirements is demonstrated if you are in compliance with the requirements of §60.5400.

(g) For each sweetening unit affected facility at onshore natural gas processing plants, you must demonstrate continuous compliance with the standards for SO₂ specified in §60.5405(b) according to paragraphs (g)(1) and (2) of this section.

(1) The minimum required SO₂ emission reduction efficiency (Z_c) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology.

(i) If $R \geq Z_c$, your affected facility is in compliance.

(ii) If $R < Z_c$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in §60.5406(c)(1).

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58442, Sept. 23, 2013; 79 FR 79039, Dec. 31, 2014; 81 FR 35897, June 3, 2016]

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§60.5416 What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my storage vessel, centrifugal compressor and reciprocating compressor affected facilities?

For each closed vent system or cover at your storage vessel, centrifugal compressor and reciprocating compressor affected facility, you must comply with the applicable requirements of paragraphs (a) through (c) of this section.

(a) *Inspections for closed vent systems and covers installed on each centrifugal compressor or reciprocating compressor affected facility.* Except as provided in paragraphs (b)(11) and (12) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) and (2) of this section, inspect each cover according to the procedures

and schedule specified in paragraph (a)(3) of this section, and inspect each bypass device according to the procedures of paragraph (a)(4) of this section.

(1) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (e.g., a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1)(i) and (ii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420(c)(6).

(ii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (b) of this section to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. You must maintain records of the inspection results as specified in §60.5420(c)(6).

(2) For closed vent system components other than those specified in paragraph (a)(1) of this section, you must meet the requirements of paragraphs (a)(2)(i) through (iii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420(c)(6).

(ii) Conduct annual inspections according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the components or connections operate with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420(c)(6).

(iii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must maintain records of the inspection results as specified in §60.5420(c)(6).

(3) For each cover, you must meet the requirements in paragraphs (a)(3)(i) and (ii) of this section.

(i) Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (e.g., fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(ii) You must initially conduct the inspections specified in paragraph (a)(3)(i) of this section following the installation of the cover. Thereafter, you must perform the inspection at least once every calendar year, except as provided in paragraphs (b)(11) and (12) of this section. You must maintain records of the inspection results as specified in §60.5420(c)(7).

(4) For each bypass device, except as provided for in §60.5411, you must meet the requirements of paragraphs (a)(4)(i) or (ii) of this section.

(i) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere.

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections according to §60.5420(c)(8).

(b) *No detectable emissions test methods and procedures.* If you are required to conduct an inspection of a closed vent system or cover at your centrifugal compressor or reciprocating compressor affected facility as specified in paragraphs (a)(1), (2), or (3) of this section, you must meet the requirements of paragraphs (b)(1) through (13) of this section.

(1) You must conduct the no detectable emissions test procedure in accordance with Method 21 at 40 CFR part 60, appendix A-7.

(2) The detection instrument must meet the performance criteria of Method 21 at 40 CFR part 60, appendix A-7, except that the instrument response factor criteria in section 3.1.2(a) of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) You must calibrate the detection instrument before use on each day of its use by the procedures specified in Method 21 at 40 CFR part 60, appendix A-7.

(4) Calibration gases must be as specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in Method 21 at 40 CFR part 60, appendix A-7.

(6) Your detection instrument must meet the performance criteria specified in paragraphs (b)(6)(i) and (ii) of this section.

(i) Except as provided in paragraph (b)(6)(ii) of this section, the detection instrument must meet the performance criteria of Method 21 at 40 CFR part 60, appendix A-7, except the instrument response factor criteria in section 3.1.2(a) of Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inerts that are not organic hazardous air pollutants or volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(ii) If no instrument is available that will meet the performance criteria specified in paragraph (b)(6)(i) of this section, you may adjust the instrument readings by multiplying by the average

response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (b)(6)(i) of this section.

(7) You must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (b)(7)(i) or (ii) of this section.

(i) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(ii) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (b)(5) of this section with the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (b)(7) of this section is less than 500 parts per million by volume.

(9) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (b)(9)(i) and (ii) of this section, except as provided in paragraph (b)(10) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 15 calendar days after the leak is detected.

(10) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(11) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (b)(11)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a)(1), (2), or (3) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(12) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (b)(12)(i) and (ii) of this section are

met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(13) *Records*. Records shall be maintained as specified in this section and in §60.5420(c)(9).

(c) *Cover and closed vent system inspections for storage vessel affected facilities*. If you install a control device or route emissions to a process, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (c)(1) of this section, inspect each cover according to the procedures and schedule specified in paragraph (c)(2) of this section, and inspect each bypass device according to the procedures of paragraph (c)(3) of this section. You must also comply with the requirements of (c)(4) through (7) of this section.

(1) For each closed vent system, you must conduct an inspection at least once every calendar month as specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in §60.5420(c)(6).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(2) For each cover, you must conduct inspections at least once every calendar month as specified in paragraphs (c)(2)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in §60.5420(c)(7).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (e.g., fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(3) For each bypass device, except as provided for in §60.5411(c)(3)(ii), you must meet the requirements of paragraphs (c)(3)(i) or (ii) of this section.

(i) You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm, or initiate notification via remote alarm to the nearest

field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420(c)(8).

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections and records of each time the key is checked out, if applicable, according to §60.5420(c)(8).

(4) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (c)(4)(i) through (iii) of this section, except as provided in paragraph (c)(5) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 30 calendar days after the leak is detected.

(iii) Grease or another applicable substance must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

(5) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(6) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (c)(6)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (c)(1) or (2) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(7) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (c)(7)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

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§60.5417 What are the continuous control device monitoring requirements for my storage vessel or centrifugal compressor affected facility?

You must meet the applicable requirements of this section to demonstrate continuous compliance for each control device used to meet emission standards for your storage vessel or centrifugal compressor affected facility.

(a) For each control device used to comply with the emission reduction standard for centrifugal compressor affected facilities in §60.5380, you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with §60.5412(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section.

(b) You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or is used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) If you are required to install a continuous parameter monitoring system, you must meet the specifications and requirements in paragraphs (c)(1) through (4) of this section.

(1) Each continuous parameter monitoring system must measure data values at least once every hour and record the parameters in paragraphs (c)(1)(i) or (ii) of this section.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(2) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your approved site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §60.13(b).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §60.7(c), (d), and (f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in accordance with the site-specific monitoring plan.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in either paragraph (d)(1), (2), or (3) of this section.

(1) A continuous monitoring system that measures the operating parameters in paragraphs (d)(1)(i) through (viii) of this section, as applicable.

(i) For a thermal vapor incinerator that demonstrates during the performance test conducted under §60.5413 that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{C}$, or ± 2.5 $^{\circ}\text{C}$, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(ii) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{C}$, or ± 2.5 $^{\circ}\text{C}$, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

(iv) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{C}$, or ± 2.5 $^{\circ}\text{C}$, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(v) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{C}$, or ± 2.8 $^{\circ}\text{C}$, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(vi) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(1)(vi)(A) and (B) of this section.

(A) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(B) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{C}$, or ± 2.5 $^{\circ}\text{C}$, whichever value is greater.

(vii) For a nonregenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a performance test performed as specified in §60.5413(b). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(viii) For a combustion control device whose model is tested under §60.5413(d), a continuous monitoring system meeting the requirements of paragraphs (d)(1)(viii)(A) and (B) of this section.

(A) The continuous monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ± 2 percent or better. The flow rate at the inlet to the combustion device must not exceed the maximum or minimum flow rate determined by the manufacturer.

(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the control device.

(2) An organic monitoring device equipped with a continuous recorder that measures the concentration level of organic compounds in the exhaust vent stream from the control device. The monitor must meet the requirements of Performance Specification 8 or 9 of 40 CFR part 60, appendix B. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications.

(3) A continuous monitoring system that measures operating parameters other than those specified in paragraph (d)(1) or (2) of this section, upon approval of the Administrator as specified in §60.13(i).

(e) You must calculate the daily average value for each monitored operating parameter for each operating day, using the data recorded by the monitoring system, except for inlet gas flow rate. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of §60.5412(a). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) If you conduct performance tests in accordance with the requirements of §60.5413(b) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412(a), then you must establish the minimum operating parameter value or the maximum operating parameter value based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(ii) If you use a condenser design analysis in accordance with the requirements of §60.5413(c) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412(a), then you must establish the minimum operating parameter value or the maximum operating parameter value based on the condenser design analysis and supplemented, as necessary, by the condenser manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under §60.5413(d) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412(a), then your control device inlet gas flow rate must not exceed the maximum or minimum inlet gas flow rate determined by the manufacturer.

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of §60.5413(b) to demonstrate that the condenser achieves the applicable performance requirements in §60.5412(a), then the condenser performance curve must be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(ii) If you use a control device design analysis in accordance with the requirements of §60.5413(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in §60.5412(a), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (g)(6) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (6) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section.

(2) If you meet §60.5412(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in §60.5415(e)(8)(iv) is less than 95.0 percent.

(3) If you meet §60.5412(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in §60.5415(e)(8)(iv)(A) or (B) is less than 90.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraphs (g)(5)(i) and (ii) of this section are met.

(i) For each bypass line subject to §60.5411(a)(3)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to §60.5411(a)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under §60.5413(d), a deviation occurs when the conditions of paragraphs (g)(6)(i) or (ii) are met.

(i) The inlet gas flow rate exceeds the maximum established during the test conducted under §60.5413(d).

(ii) Failure of the quarterly visible emissions test conducted under §60.5413(e)(3) occurs.

(h) For each control device used to comply with the emission reduction standard in §60.5395(d)(1) for your storage vessel affected facility, you must demonstrate continuous compliance according to paragraphs (h)(1) through (h)(3) of this section. You are exempt from the requirements of this paragraph if you install a control device model tested in accordance with §60.5413(d)(2) through (10), which meets the criteria in §60.5413(d)(11), the reporting requirement in §60.5413(d)(12), and meet the continuous compliance requirement in §60.5413(e).

(1) For each combustion device you must conduct inspections at least once every calendar month according to paragraphs (h)(1)(i) through (iv) of this section. Monthly inspections must be separated by at least 14 calendar days.

(i) Conduct visual inspections to confirm that the pilot is lit when vapors are being routed to the combustion device and that the continuous burning pilot flame is operating properly.

(ii) Conduct inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22, 40 CFR part 60, appendix A. The observation period shall be 15

minutes. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period.

(iii) Conduct olfactory, visual and auditory inspections of all equipment associated with the combustion device to ensure system integrity.

(iv) For any absence of pilot flame, or other indication of smoking or improper equipment operation (e.g., visual, audible, or olfactory), you must ensure the equipment is returned to proper operation as soon as practicable after the event occurs. At a minimum, you must perform the procedures specified in paragraphs (h)(1)(iv)(A) and (B) of this section.

(A) You must check the air vent for obstruction. If an obstruction is observed, you must clear the obstruction as soon as practicable.

(B) You must check for liquid reaching the combustor.

(2) For each vapor recovery device, you must conduct inspections at least once every calendar month to ensure physical integrity of the control device according to the manufacturer's instructions. Monthly inspections must be separated by at least 14 calendar days.

(3) Each control device must be operated following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions. Records of the manufacturer's written operating instructions, procedures, and maintenance schedule must be available for inspection as specified in §60.5420(c)(13).

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58443, Sept. 23, 2013]

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§60.5420 What are my notification, reporting, and recordkeeping requirements?

(a) You must submit the notifications according to paragraphs (a)(1) and (2) of this section if you own or operate one or more of the affected facilities specified in §60.5365 that was constructed, modified, or reconstructed during the reporting period.

(1) If you own or operate a gas well, pneumatic controller, centrifugal compressor, reciprocating compressor or storage vessel affected facility you are not required to submit the notifications required in §60.7(a)(1), (3), and (4).

(2)(i) If you own or operate a gas well affected facility, you must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the API well number, the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format.

(ii) If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you are considered to have met the advance notification requirements of paragraph (a)(2)(i) of this section.

(b) Reporting requirements. You must submit annual reports containing the information specified in paragraphs (b)(1) through (6) of this section to the Administrator and performance test reports as specified in paragraph (b)(7) or (8) of this section. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to §60.5410. Subsequent annual reports are due no later than same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (6) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

(1) The general information specified in paragraphs (b)(1)(i) through (iv) of this section.

(i) The company name and address of the affected facility.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(2) For each gas well affected facility, the information in paragraphs (b)(2)(i) through (ii) of this section.

(i) Records of each well completion operation as specified in paragraph (c)(1)(i) through (iv) of this section for each gas well affected facility conducted during the reporting period. In lieu of submitting the records specified in paragraph (c)(1)(i) through (iv), the owner or operator may submit a list of the well completions with hydraulic fracturing completed during the reporting period and the records required by paragraph (c)(1)(v) of this section for each well completion.

(ii) Records of deviations specified in paragraph (c)(1)(ii) of this section that occurred during the reporting period.

(3) For each centrifugal compressor affected facility, the information specified in paragraphs (b)(3)(i) and (ii) of this section.

(i) An identification of each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period.

(ii) Records of deviations specified in paragraph (c)(2) of this section that occurred during the reporting period.

(iii) If required to comply with §60.5380(a)(1), the records specified in paragraphs (c)(6) through (11) of this section.

(4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) through (ii) of this section.

(i) The cumulative number of hours of operation or the number of months since initial startup, since October 15, 2012, or since the previous reciprocating compressor rod packing replacement, whichever is later.

(ii) Records of deviations specified in paragraph (c)(3)(iii) of this section that occurred during the reporting period.

(5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (iii) of this section.

(i) An identification of each pneumatic controller constructed, modified or reconstructed during the reporting period, including the identification information specified in §60.5390(b)(2) or (c)(2).

(ii) If applicable, documentation that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than 6 standard cubic feet per hour are required and the reasons why.

(iii) Records of deviations specified in paragraph (c)(4)(v) of this section that occurred during the reporting period.

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) through (vii) of this section.

(i) An identification, including the location, of each storage vessel affected facility for which construction, modification or reconstruction commenced during the reporting period. The location of the storage vessel shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) Documentation of the VOC emission rate determination according to §60.5365(e) for each storage vessel that became an affected facility during the reporting period or is returned to service during the reporting period.

(iii) Records of deviations specified in paragraph (c)(5)(iii) of this section that occurred during the reporting period.

(iv) You must submit a notification identifying each Group 1 storage vessel affected facility in your initial annual report. You must include the location of the storage vessel, in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(v) A statement that you have met the requirements specified in §60.5410(h)(2) and (3).

(vi) You must identify each storage vessel affected facility that is removed from service during the reporting period as specified in §60.5395(f)(1)(ii), including the date the storage vessel affected facility was removed from service.

(vii) You must identify each storage vessel affected facility returned to service during the reporting period as specified in §60.5395(f)(3), including the date the storage vessel affected facility was returned to service.

(7)(i) Within 60 days after the date of completing each performance test (see §60.8 of this part) as required by this subpart, except testing conducted by the manufacturer as specified in

§60.5413(d), you must submit the results of the performance tests required by this subpart to the EPA as follows. You must use the latest version of the EPA's Electronic Reporting Tool (ERT) (see <http://www.epa.gov/ttn/chief/ert/index.html>) existing at the time of the performance test to generate a submission package file, which documents the performance test. You must then submit the file generated by the ERT through the EPA's Compliance and Emissions Data Reporting Interface (CEDRI), which can be accessed by logging in to the EPA's Central Data Exchange (CDX) (<https://cdx.epa.gov/>). Only data collected using test methods supported by the ERT as listed on the ERT Web site are subject to this requirement for submitting reports electronically. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to EPA via CDX as described earlier in this paragraph. At the discretion of the delegated authority, you must also submit these reports, including the confidential business information, to the delegated authority in the format specified by the delegated authority. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test to the Administrator at the appropriate address listed in §60.4.

(ii) All reports, except as specified in paragraph (b)(8) of this section, required by this subpart not subject to the requirements in paragraph (a)(2)(i) of this section must be sent to the Administrator at the appropriate address listed in §60.4 of this part. The Administrator or the delegated authority may request a report in any form suitable for the specific case (e.g., by commonly used electronic media such as Excel spreadsheet, on CD or hard copy).

(8) For enclosed combustors tested by the manufacturer in accordance with §60.5413(d), an electronic copy of the performance test results required by §60.5413(d) shall be submitted via email to *Oil_____and_____Gas_____PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: epa.gov/airquality/oilandgas/.

(c) *Recordkeeping requirements.* You must maintain the records identified as specified in §60.7(f) and in paragraphs (c)(1) through (14) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years.

(1) The records for each gas well affected facility as specified in paragraphs (c)(1)(i) through (v) of this section.

(i) Records identifying each well completion operation for each gas well affected facility;

(ii) Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in §60.5375.

(iii) Records required in §60.5375(b) or (f) for each well completion operation conducted for each gas well affected facility that occurred during the reporting period. You must maintain the records specified in paragraphs (c)(1)(iii)(A) and (B) of this section.

(A) For each gas well affected facility required to comply with the requirements of §60.5375(a), you must record: The location of the well; the API well number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time of each attempt to direct flowback to a separator as required in §60.5375(a)(1)(i); the date and time of each occurrence of returning to the initial flowback stage under §60.5375(a)(1)(i); and the date and time that the well

was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery to the flow line; duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours of time.

(B) For each gas well affected facility required to comply with the requirements of §60.5375(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the flow line.

(iv) For each gas well facility for which you claim an exception under §60.5375(a)(3), you must record: The location of the well; the API well number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.

(v) For each gas well affected facility required to comply with both §60.5375(a)(1) and (3), if you are using a digital photograph in lieu of the records required in paragraphs (c)(1)(i) through (iv) of this section, you must retain the records of the digital photograph as specified in §60.5410(a)(4).

(2) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in §60.5380.

(3) For each reciprocating compressors affected facility, you must maintain the records in paragraphs (c)(3)(i) through (iii) of this section.

(i) Records of the cumulative number of hours of operation or number of months since initial startup or October 15, 2012, or the previous replacement of the reciprocating compressor rod packing, whichever is later.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system as specified in §60.5385(a)(3).

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in §60.5385.

(4) For each pneumatic controller affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (v) of this section.

(i) Records of the date, location and manufacturer specifications for each pneumatic controller constructed, modified or reconstructed.

(ii) Records of the demonstration that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required and the reasons why.

(iii) If the pneumatic controller is not located at a natural gas processing plant, records of the manufacturer's specifications indicating that the controller is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour.

(iv) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(v) Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in §60.5390.

(5) Except as specified in paragraph (c)(5)(v) of this section, for each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) through (iv) of this section.

(i) If required to reduce emissions by complying with §60.5395(d)(1), the records specified in §§60.5420(c)(6) through (8), 60.5416(c)(6)(ii), and 60.6516(c)(7)(ii) of this subpart.

(ii) Records of each VOC emissions determination for each storage vessel affected facility made under §60.5365(e) including identification of the model or calculation methodology used to calculate the VOC emission rate.

(iii) Records of deviations in cases where the storage vessel was not operated in compliance with the requirements specified in §§60.5395, 60.5411, 60.5412, and 60.5413, as applicable.

(iv) For storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships), records indicating the number of consecutive days that the vessel is located at the site. If a storage vessel is removed from the site and, within 30 days, is either returned to or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the original storage vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

(v) You must maintain records of the identification and location of each storage vessel affected facility.

(6) Records of each closed vent system inspection required under §60.5416(a)(1) and (2) for centrifugal or reciprocating compressors or §60.5416(c)(1) for storage vessels.

(7) A record of each cover inspection required under §60.5416(a)(3) for centrifugal or reciprocating compressors or §60.5416(c)(2) for storage vessels.

(8) If you are subject to the bypass requirements of §60.5416(a)(4) for centrifugal or reciprocating compressors or §60.5416(c)(3) for storage vessels, a record of each inspection or a record each time the key is checked out or a record of each time the alarm is sounded.

(9) If you are subject to the closed vent system no detectable emissions requirements of §60.5416(b) for centrifugal or reciprocating compressors, a record of the monitoring conducted in accordance with §60.5416(b).

(10) For each centrifugal compressor affected facility, records of the schedule for carbon replacement (as determined by the design analysis requirements of §60.5413(c)(2) or (3)) and records of each carbon replacement as specified in §60.5412(c)(1).

(11) For each centrifugal compressor subject to the control device requirements of §60.5412(a), (b), and (c), records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

(12) For each carbon adsorber installed on storage vessel affected facilities, records of the schedule for carbon replacement (as determined by the design analysis requirements of §60.5412(d)(2)) and records of each carbon replacement as specified in §60.5412(c)(1).

(13) For each storage vessel affected facility subject to the control device requirements of §60.5412(c) and (d), you must maintain records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in §60.5417(h). You must maintain records of EPA Method 22, 40 CFR part 60, appendix A, section 11 results, which include: company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22-1 in EPA Method 22, 40 CFR part 60, appendix A. Manufacturer's operating instructions, procedures and maintenance schedule must be available for inspection.

(14) A log of records as specified in §§60.5412(d)(1)(iii) and 60.5413(e)(4) for all inspection, repair and maintenance activities for each control device failing the visible emissions test.

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§60.5421 What are my additional recordkeeping requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraph (b) of this section in addition to the requirements of §60.486a.

(b) The following recordkeeping requirements apply to pressure relief devices subject to the requirements of §60.5401(b)(1) of this subpart.

(1) When each leak is detected as specified in §60.5401(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(2) When each leak is detected as specified in §60.5401(b)(2), the following information must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) "Above 500 ppm" if the maximum instrument reading measured by the methods specified in paragraph (a) of this section after each repair attempt is 500 ppm or greater.

(v) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4a(a). The designation of equipment subject to the provisions of §60.482-4a(a) must be signed by the owner or operator.

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§60.5422 What are my additional reporting requirements for my affected facility subject to VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of §60.487a(a), (b), (c)(2)(i) through (iv), and (c)(2)(vii) through (viii).

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in §60.487a(b)(1) through (4): Number of pressure relief devices subject to the requirements of §60.5401(b) except for those pressure relief devices designated for no detectable emissions under the provisions of §60.482-4a(a) and those pressure relief devices complying with §60.482-4a(c).

(c) An owner or operator must include the following information in all semiannual reports in addition to the information required in §60.487a(c)(2)(i) through (vi):

(1) Number of pressure relief devices for which leaks were detected as required in §60.5401(b)(2); and

(2) Number of pressure relief devices for which leaks were not repaired as required in §60.5401(b)(3).

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§60.5423 What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?

(a) You must retain records of the calculations and measurements required in §§60.5405(a) and (b) and 60.5407(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under §60.7(d) of the General Provisions.

(b) You must submit a report of excess emissions to the Administrator in your annual report if you had excess emissions during the reporting period. For the purpose of these reports, excess emissions are defined as:

(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z).

(2) For any affected facility electing to comply with the provisions of §60.5407(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of §60.5407(b)(2). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours.

(c) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less than 2 LT/D of H₂S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H₂S expressed as sulfur.

(d) If you elect to comply with §60.5407(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H₂S expressed as sulfur.

(e) The requirements of paragraph (b) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (b) of this section, provided that they comply with the requirements established by the state.

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§60.5425 What part of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

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§60.5430 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VVa of part 60; and the following terms shall have the specific meanings given them.

Acid gas means a gas stream of hydrogen sulfide (H₂S) and carbon dioxide (CO₂) that has been separated from sour natural gas by a sweetening unit.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

API Gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(1) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where

(i) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$$A = Y \times (B \div 100);$$

(ii) The percent Y is determined from the following equation: $Y = 1.0 - 0.575 \log X$, where X is 2011 minus the year of construction; and

(iii) The applicable basic annual asset guideline repair allowance, B, is 4.5.

(2) [Reserved]

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding \$25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including but not limited to general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

City gate means the delivery point at which natural gas is transferred from a transmission pipeline to the local gas utility.

Collection system means any infrastructure that conveys gas or liquids from the well site to another location for treatment, storage, processing, recycling, disposal or other handling.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions.

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure from fields, in transmission pipelines, or into storage.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions.

Continuous bleed means a continuous flow of pneumatic supply natural gas to the process control device (e.g., level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.

Crude Oil and Natural Gas Production source category means:

(1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and

(2) Natural gas production and processing, which includes the well and extends to, but does not include, the point of custody transfer to the natural gas transmission and storage segment.

Custody transfer means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Dehydrator means a device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber).

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

Equipment, as used in the standards and requirements in this subpart relative to the equipment leaks of VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this subpart.

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used transport field gas from a field to the main pipeline in the area.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Flow line means a pipeline used to transport oil and/or gas to a processing facility, a mainline pipeline, re-injection, or routed to a process or other useful purpose.

Flowback means the process of allowing fluids and entrained solids to flow from a natural gas well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term *flowback* also means the fluids and entrained solids that emerge from a natural gas well during the flowback process. The *flowback period* begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The *flowback period* ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage.

Gas processing plant process unit means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Gas well or natural gas well means an onshore well drilled principally for production of natural gas.

Group 1 storage vessel means a storage vessel, as defined in this section, for which construction, modification or reconstruction has commenced after August 23, 2011, and on or before April 12, 2013.

Group 2 storage vessel means a storage vessel, as defined in this section, for which construction, modification or reconstruction has commenced after April 12, 2013, and on or before September 18, 2015.

Hydraulic fracturing or refracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in §60.485a(e) or §60.5401(g)(2) of this part.

In wet gas service means that a compressor or piece of equipment contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Initial flowback stage means the period during a well completion operation which begins at the onset of flowback and ends at the separation flowback stage.

Intermediate hydrocarbon liquid means any naturally occurring, unrefined petroleum liquid.

Intermittent/snap-action pneumatic controller means a pneumatic controller that vents non-continuously.

Liquefied natural gas unit means a unit used to cool natural gas to the point at which it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

Local distribution company (LDC) custody transfer station means a metering station where the LDC receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

Low pressure gas well means a well with reservoir pressure and vertical well depth such that $0.445 \times \text{reservoir pressure (in psia)} - 0.038 \times \text{true vertical well depth (in feet)}$ minus 67.578 psia is less than the flow line pressure at the sales meter.

Maximum average daily throughput means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.

Natural gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Natural gas transmission and storage segment means the transport or storage of natural gas prior to delivery to a “local distribution company custody transfer station” (as defined in this section) or to a final end user (if there is no local distribution company custody transfer station). For the purposes of this subpart, natural gas enters the natural gas transmission and storage segment after the natural gas processing plant, when present. If no natural gas processing plant is present, natural gas enters the natural gas transmission and storage segment after the point of “custody transfer” (as defined in this section). A compressor station that transports natural gas prior to the point of “custody transfer” or to a natural gas processing plant (if present) is not considered a part of the natural gas transmission and storage segment.

Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Non-natural gas-driven pneumatic controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Produced water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

Recovered gas means gas recovered through the separation process during flowback.

Recovered liquids means any crude oil, condensate or produced water recovered through the separation process during flowback.

Reduced emissions completion means a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.

Reduced sulfur compounds means H₂S, carbonyl sulfide (COS), and carbon disulfide (CS₂).

Removed from service means that a storage vessel affected facility has been physically isolated and disconnected from the process for a purpose other than maintenance in accordance with §60.5395(f)(1).

Responsible official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding \$25 million (in second quarter 1980 dollars); or

(ii) The delegation of authority to such representatives is approved in advance by the permitting authority;

(2) For a partnership or sole proprietorship: A general partner or the proprietor, respectively;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Returned to service means that a Group 1 or Group 2 storage vessel affected facility that was removed from service has been:

(1) Reconnected to the original source of liquids or has been used to replace any storage vessel affected facility; or

(2) Installed in any location covered by this subpart and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Salable quality gas means natural gas that meets the flow line or collection system operator specifications, regardless of whether such gas is sold.

Separation flowback stage means the period during a well completion operation when it is technically feasible for a separator to function. The *separation flowback stage* ends either at the startup of production, or when the well is shut in and permanently disconnected from the flowback equipment.

Startup of production means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water.

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of §60.5395(f) until such time as such tank or other vessel has been returned to service. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of §60.5395(f) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by §60.5420(c)(5)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

(2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

Sulfur production rate means the rate of liquid sulfur accumulation from the sulfur recovery unit.

Sulfur recovery unit means a process device that recovers element sulfur from acid gas.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream.

Total Reduced Sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A to part 60 of this chapter.

Total SO₂ equivalents means the sum of volumetric or mass concentrations of the sulfur compounds obtained by adding the quantity existing as SO₂ to the quantity of SO₂ that would be obtained if all reduced sulfur compounds were converted to SO₂ (ppmv or kg/dscm (lb/dscf)).

Underground storage vessel means a storage vessel stored below ground.

Well means an oil or gas well, a hole drilled for the purpose of producing oil or gas, or a well into which fluids are injected.

Well completion means the process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.

Well completion operation means any well completion with hydraulic fracturing or refracturing occurring at a gas well affected facility.

Well completion vessel means a vessel that contains *flowback* during a well completion operation following hydraulic fracturing or refracturing. A well completion vessel may be a lined earthen pit, a tank or other vessel that is skid-mounted or portable. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart.

Well site means one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, gas well, or injection well and its associated well pad.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

[77 FR 49542, Aug. 16, 2012, as amended at 78 FR 58447, Sept. 23, 2013; 79 FR 79040, Dec. 31, 2014; 80 FR 48268, Aug. 12, 2015; 81 FR 35898, June 3, 2016; 85 FR 57069, Sept. 14, 2020]

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Table 1 to Subpart OOOO of Part 60—Required Minimum Initial SO₂ Emission Reduction Efficiency (Z_i)

H ₂ S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	$2.0 \leq X \leq 5.0$	$5.0 < X \leq 15.0$	$15.0 < X \leq 300.0$	$X > 300.0$
$Y \geq 50$	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 99.9, whichever is smaller.		
$20 \leq Y < 50$	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller		97.9

$10 \leq Y < 20$	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 93.5, whichever is smaller	93.5	93.5
$Y < 10$	79.0	79.0	79.0	79.0

[78 FR 58447, Sept. 23, 2013]

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Table 2 to Subpart OOOO of Part 60—Required Minimum SO₂ Emission Reduction Efficiency (Z_c)

H ₂ S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	$2.0 \leq X \leq 5.0$	$5.0 < X \leq 15.0$	$15.0 < X \leq 300.0$	$X > 300.0$
$Y \geq 50$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 99.9, whichever is smaller.		
$20 \leq Y < 50$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 97.5, whichever is smaller		97.5
$10 \leq Y < 20$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller	90.8	90.8
$Y < 10$	74.0	74.0	74.0	74.0

X = The sulfur feed rate from the sweetening unit (*i.e.*, the H₂S in the acid gas), expressed as sulfur, Mg/D(LT/D), rounded to one decimal place.

Y = The sulfur content of the acid gas from the sweetening unit, expressed as mole percent H₂S (dry basis) rounded to one decimal place.

Z = The minimum required sulfur dioxide (SO₂) emission reduction efficiency, expressed as percent carried to one decimal place. Z_i refers to the reduction efficiency required at the initial performance test. Z_c refers to the reduction efficiency required on a continuous basis after compliance with Z_i has been demonstrated.

[78 FR 58447, Sept. 23, 2013]

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Table 3 to Subpart OOOO of Part 60—Applicability of General Provisions to Subpart OOOO

As stated in §60.5425, you must comply with the following applicable General Provisions:

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§60.1	General applicability of the General Provisions	Yes.	

§60.2	Definitions	Yes	Additional terms defined in §60.5430.
§60.3	Units and abbreviations	Yes.	
§60.4	Address	Yes.	
§60.5	Determination of construction or modification	Yes.	
§60.6	Review of plans	Yes.	
§60.7	Notification and record keeping	Yes	Except that §60.7 only applies as specified in §60.5420(a).
§60.8	Performance tests	Yes	Performance testing is required for control devices used on storage vessels and centrifugal compressors.
§60.9	Availability of information	Yes.	
§60.10	State authority	Yes.	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart OOOO.
§60.12	Circumvention	Yes.	
§60.13	Monitoring requirements	Yes	Continuous monitors are required for storage vessels.
§60.14	Modification	Yes.	
§60.15	Reconstruction	Yes.	Except that §60.15(d) does not apply to gas wells, pneumatic controllers, centrifugal compressors, reciprocating compressors or storage vessels.
§60.16	Priority list	Yes.	
§60.17	Incorporations by reference	Yes.	
§60.18	General control device requirements	Yes	Except that the period of visible emissions shall not exceed a total of 1 minute during any 15-minute period instead of 5 minutes during any 2 consecutive hours as required in §60.18(c).
§60.19	General notification and reporting requirement	Yes.	

[77 FR 49542, Aug. 16, 2012, as amended at 81 FR 35898, June 3, 2016]

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NSPS Subpart OOOOa—Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015

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SOURCE: 81 FR 35898, June 3, 2016, unless otherwise noted.

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§60.5360a What is the purpose of this subpart?

(a) This subpart establishes emission standards and compliance schedules for the control of the pollutant greenhouse gases (GHG). The greenhouse gas standard in this subpart is in the form of a limitation on emissions of methane from affected facilities in the crude oil and natural gas source category that commence construction, modification, or reconstruction after September 18, 2015. This subpart also establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO₂) emissions from affected facilities in the crude oil and natural gas source category that commence construction, modification or reconstruction after September 18, 2015. The effective date of the rule is August 2, 2016.

(b) *Prevention of Significant Deterioration (PSD) and title V thresholds for Greenhouse Gases.*

(1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, §51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the “pollutant that is subject to the standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is subject to regulation under the Clean Air Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the “pollutant that is subject to any standard promulgated under section 111 of the Act” shall be considered to be the pollutant that otherwise is “subject to regulation” as defined in 40 CFR 71.2.

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§60.5365a Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (j) of this section for which you commence construction, modification, or reconstruction after September 18, 2015.

(a) Each well affected facility, which is a single well that conducts a well completion operation following hydraulic fracturing or refracturing. The provisions of this paragraph do not affect the affected facility status of well sites for the purposes of §60.5397a. The provisions of paragraphs (a)(1) through (4) of this section apply to wells that are hydraulically refractured:

(1) A well that conducts a well completion operation following hydraulic refracturing is not an affected facility, provided that the requirements of §60.5375a(a)(1) through (4) are met. However, hydraulic refracturing of a well constitutes a modification of the well site for purposes of paragraph (i)(3)(iii) of this section, regardless of affected facility status of the well itself.

(2) A well completion operation following hydraulic refracturing not conducted pursuant to §60.5375a(a)(1) through (4) is a modification to the well.

(3) Except as provided in §60.5365a(i)(3)(iii), refracturing of a well, by itself, does not affect the modification status of other equipment, process units, storage vessels, compressors, pneumatic pumps, or pneumatic controllers.

(4) A well initially constructed after September 18, 2015, that conducts a well completion operation following hydraulic refracturing is considered an affected facility regardless of this provision.

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(d) Each pneumatic controller affected facility:

(1) Each pneumatic controller affected facility not located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh.

(2) Each pneumatic controller affected facility located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller.

(e) Each storage vessel affected facility, which is a single storage vessel with the potential for VOC emissions equal to or greater than 6 tpy as determined according to this section. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in this subsection. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a federal, state, local or tribal authority.

(1) For each new, modified or reconstructed storage vessel you must determine the potential for VOC emissions within 30 days after liquids first enter the storage vessel, except as provided in paragraph (e)(3)(iv) of this section. For each new, modified or reconstructed storage vessel receiving liquids pursuant to the standards for well affected facilities in §60.5375a, including wells subject to §60.5375a(f), you must determine the potential for VOC emissions within 30 days after startup of production of the well.

(2) A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy shall remain an affected facility under this subpart.

(3) For storage vessels not subject to a legally and practically enforceable limit in an operating permit or other requirement established under federal, state, local or tribal authority, any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of VOC potential to emit for purposes of determining affected facility status, provided you comply with the requirements in paragraphs (e)(3)(i) through (iv) of this section.

(i) You meet the cover requirements specified in §60.5411a(b).

(ii) You meet the closed vent system requirements specified in §60.5411a(c) and (d).

(iii) You must maintain records that document compliance with paragraphs (e)(3)(i) and (ii) of this section.

(iv) In the event of removal of apparatus that recovers and routes vapor to a process, or operation that is inconsistent with the conditions specified in paragraphs (e)(3)(i) and (ii) of this section, you must determine the storage vessel's potential for VOC emissions according to this section within 30 days of such removal or operation.

(4) The following requirements apply immediately upon startup, startup of production, or return to service. A storage vessel affected facility that is reconnected to the original source of liquids is a storage vessel affected facility subject to the same requirements that applied before being removed from service. Any storage vessel that is used to replace any storage vessel affected facility is subject to the same requirements that apply to the storage vessel affected facility being replaced.

(5) A storage vessel with a capacity greater than 100,000 gallons used to recycle water that has been passed through two stage separation is not a storage vessel affected facility.

(f) The group of all equipment within a process unit is an affected facility. (1) Addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(2) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit is covered by §§60.5400a, 60.5401a, 60.5402a, 60.5421a, and 60.5422a if it is located at an onshore natural gas processing plant. Equipment not located at the onshore natural gas processing plant site is exempt from the provisions of §§60.5400a, 60.5401a, 60.5402a, 60.5421a, and 60.5422a.

(3) The equipment within a process unit of an affected facility located at onshore natural gas processing plants and described in paragraph (f) of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG, or GGGa of this part.

(g) Sweetening units located at onshore natural gas processing plants that process natural gas produced from either onshore or offshore wells.

(1) Each sweetening unit that processes natural gas is an affected facility; and

(2) Each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility.

(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H₂S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in §60.5423a(c) but are not required to comply with §§60.5405a through 60.5407a and §§60.5410a(g) and 60.5415a(g).

(4) Sweetening facilities producing acid gas that is completely re-injected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to §§60.5405a through 60.5407a, 60.5410a(g), 60.5415a(g), and 60.5423a.

(h) Each pneumatic pump affected facility:

(1) For natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven diaphragm pump.

(2) For well sites, each pneumatic pump affected facility, which is a single natural gas-driven diaphragm pump. A single natural gas-driven diaphragm pump that is in operation less than 90 days per calendar year is not an affected facility under this subpart provided the owner/operator keeps records of the days of operation each calendar year and submits such records to the EPA Administrator (or delegated enforcement authority) upon request. For the purposes of this section, any period of operation during a calendar day counts toward the 90 calendar day threshold.

(i) Except as provided in §60.5365a(i)(2), the collection of fugitive emissions components at a well site, as defined in §60.5430a, is an affected facility.

(1) [Reserved]

(2) A well site that only contains one or more wellheads is not an affected facility under this subpart. The affected facility status of a separate tank battery surface site has no effect on the affected facility status of a well site that only contains one or more wellheads.

(3) For purposes of §60.5397a, a “modification” to a well site occurs when:

(i) A new well is drilled at an existing well site;

(ii) A well at an existing well site is hydraulically fractured; or

(iii) A well at an existing well site is hydraulically refractured.

(j) The collection of fugitive emissions components at a compressor station, as defined in §60.5430a, is an affected facility. For purposes of §60.5397a, a “modification” to a compressor station occurs when:

(1) An additional compressor is installed at a compressor station; or

(2) One or more compressors at a compressor station is replaced by one or more compressors of greater total horsepower than the compressor(s) being replaced. When one or more compressors is replaced by one or more compressors of an equal or smaller total horsepower than the compressor(s) being replaced, installation of the replacement compressor(s) does not trigger a modification of the compressor station for purposes of §60.5397a.

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§60.5370a When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than August 2, 2016 or upon startup, whichever is later.

(b) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. The provisions for exemption from compliance during periods of startup, shutdown and malfunctions provided for in 40 CFR 60.8(c) do not apply to this subpart.

(c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

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§60.5375a What GHG and VOC standards apply to well affected facilities?

If you are the owner or operator of a well affected facility as described in §60.5365a(a) that also meets the criteria for a well affected facility in §60.5365(a) of subpart OOOO of this part, you must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with paragraphs (a) through (g) of this section. If you own or operate a well affected facility as described in §60.5365a(a) that does not meet the criteria for a well affected facility in §60.5365(a) of subpart OOOO of this part, you must reduce GHG and VOC emissions by complying with paragraphs (f)(3), (f)(4) or (g) for each well completion operation with hydraulic fracturing prior to November 30, 2016, and you must comply with paragraphs (a) through (g) of this section for each well completion operation with hydraulic fracturing on or after November 30, 2016.

(a) Except as provided in paragraph (f) and (g) of this section, for each well completion operation with hydraulic fracturing you must comply with the requirements in paragraphs (a)(1) through (4) of this section. You must maintain a log as specified in paragraph (b) of this section.

(1) For each stage of the well completion operation, as defined in §60.5430a, follow the requirements specified in paragraphs (a)(1)(i) through (iii) of this section.

(i) During the initial flowback stage, route the flowback into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the initial flowback stage is not subject to control under this section.

(ii) During the separation flowback stage, route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the recovered liquids into the well or another well, or route the recovered liquids to a collection system. Route the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an onsite fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If it is technically infeasible to route the recovered gas as required above, follow the requirements in paragraph (a)(3) of this section. If, at any time during the separation flowback stage, it is technically infeasible for a separator to function, you must comply with paragraph (a)(1)(i) of this section.

(iii) You must have a separator onsite during the entirety of the flowback period, except as provided in paragraphs (a)(1)(iii)(A) through (C) of this section.

(A) A well that is not hydraulically fractured or refractured with liquids, or that does not generate condensate, intermediate hydrocarbon liquids, or produced water such that there is no liquid collection system at the well site is not required to have a separator onsite.

(B) If conditions allow for liquid collection, then the operator must immediately stop the well completion operation, install a separator, and restart the well completion operation in accordance with §60.5375a(a)(1).

(C) The owner or operator of a well that meets the criteria of paragraph (a)(1)(iii)(A) or (B) of this section must submit the report in §60.5420a(b)(2) and maintain the records in §60.5420a(c)(1)(iii).

(2) [Reserved]

(3) If it is technically infeasible to route the recovered gas as required in §60.5375a(a)(1)(ii), then you must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

(4) You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

(b) You must maintain a log for each well completion operation at each well affected facility. The log must be completed on a daily basis for the duration of the well completion operation and must contain the records specified in §60.5420a(c)(1)(iii).

(c) You must demonstrate initial compliance with the standards that apply to well affected facilities as required by §60.5410a(a).

(d) You must demonstrate continuous compliance with the standards that apply to well affected facilities as required by §60.5415a(a).

(e) You must perform the required notification, recordkeeping and reporting as required by §60.5420a(a)(2), (b)(1) and (2), and (c)(1).

(f) For each well affected facility specified in paragraphs (f)(1) and (2) of this section, you must comply with the requirements of paragraphs (f)(3) and (4) of this section.

(1) Each well completion operation with hydraulic fracturing at a wildcat or delineation well.

(2) Each well completion operation with hydraulic fracturing at a non-wildcat low pressure well or non-delineation low pressure well.

(3) You must comply with either paragraph (f)(3)(i) or (f)(3)(ii) of this section, unless you meet the requirements in paragraph (g) of this section. You must also comply with paragraph (b) of this section.

(i) Route all flowback to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

(ii) Route all flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the flowback before the separator can function is not subject to control under this section. Capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame. (4) You must submit the notification as specified in §60.5420a(a)(2), submit annual reports as specified in §60.5420a(b)(1) and (2) and maintain records specified in §60.5420a(c)(1)(iii) for each wildcat and delineation well. You must submit the notification as specified in §60.5420a(a)(2), submit annual reports as specified in §60.5420a(b)(1) and (2), and maintain records as specified in §60.5420a(c)(1)(iii) and (vii) for each low pressure well.

(g) For each well affected facility with less than 300 scf of gas per stock tank barrel of oil produced, you must comply with paragraphs (g)(1) and (2) of this section.

(1) You must maintain records specified in §60.5420a(c)(1)(vi).

(2) You must submit reports specified in §60.5420a(b)(1) and (2).

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§60.5380a What GHG and VOC standards apply to centrifugal compressor affected facilities?

You must comply with the GHG and VOC standards in paragraphs (a) through (d) of this section for each centrifugal compressor affected facility.

(a)(1) You must reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411a(b). The cover must be connected through a closed vent system that meets the requirements of §60.5411a(a) and (d) and the closed vent system must be routed to a control device that meets the conditions specified in §60.5412a(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(b) You must demonstrate initial compliance with the standards that apply to centrifugal compressor affected facilities as required by §60.5410a(b).

(c) You must demonstrate continuous compliance with the standards that apply to centrifugal compressor affected facilities as required by §60.5415a(b).

(d) You must perform the reporting as required by §60.5420a(b)(1) and (3), and the recordkeeping as required by §60.5420a(c)(2), (6) through (11), and (17), as applicable.

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§60.5385a What GHG and VOC standards apply to reciprocating compressor affected facilities?

You must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with the standards in paragraphs (a) through (d) of this section for each reciprocating compressor affected facility.

(a) You must replace the reciprocating compressor rod packing according to either paragraph (a)(1) or (2) of this section, or you must comply with paragraph (a)(3) of this section.

(1) On or before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

(3) Collect the methane and VOC emissions from the rod packing using a rod packing emissions collection system that operates under negative pressure and route the rod packing emissions to a process through a closed vent system that meets the requirements of §60.5411a(a) and (d).

(b) You must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by §60.5410a(c).

(c) You must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by §60.5415a(c).

(d) You must perform the reporting as required by §60.5420a(b)(1) and (4) and the recordkeeping as required by §60.5420a(c)(3), (6) through (9), and (17), as applicable.

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§60.5390a What GHG and VOC standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the GHG and VOC standards, based on natural gas as a surrogate for GHG and VOC, in either paragraph (b)(1) or (c)(1) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) of this section are exempt from this requirement.

(a) The requirements of paragraph (b)(1) or (c)(1) of this section are not required if you determine that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required based on functional needs, including but not limited to response time, safety and positive actuation. However, you must tag such pneumatic controller with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller, as required in §60.5420a(c)(4)(ii).

(b)(1) Each pneumatic controller affected facility at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller as required in §60.5420a(c)(4)(iv).

(c)(1) Each pneumatic controller affected facility at a location other than at a natural gas processing plant must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller affected facility at a location other than at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and

identification information that allows traceability to the records for that controller as required in §60.5420a(c)(4)(iii).

(d) You must demonstrate initial compliance with standards that apply to pneumatic controller affected facilities as required by §60.5410a(d).

(e) You must demonstrate continuous compliance with standards that apply to pneumatic controller affected facilities as required by §60.5415a(d).

(f) You must perform the reporting as required by §60.5420a(b)(1) and (5) and the recordkeeping as required by §60.5420a(c)(4).

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§60.5393a What GHG and VOC standards apply to pneumatic pump affected facilities?

For each pneumatic pump affected facility you must comply with the GHG and VOC standards, based on natural gas as a surrogate for GHG and VOC, in either paragraph (a) or (b) of this section, as applicable, on or after November 30, 2016.

(a) Each pneumatic pump affected facility at a natural gas processing plant must have a natural gas emission rate of zero.

(b) For each pneumatic pump affected facility at a well site you must comply with paragraph (b)(1) or (2) of this section.

(1) If the pneumatic pump affected facility is located at a greenfield site as defined in §60.5430a, you must reduce natural gas emissions by 95.0 percent, except as provided in paragraphs (b)(3) and (4) of this section.

(2) If the pneumatic pump affected facility is not located at a greenfield site as defined in §60.5430a, you must reduce natural gas emissions by 95.0 percent, except as provided in paragraphs (b)(3), (4) and (5) of this section.

(3) You are not required to install a control device solely for the purpose of complying with the 95.0 percent reduction requirement of paragraph (b)(1) or (b)(2) of this section. If you do not have a control device installed on site by the compliance date and you do not have the ability to route to a process, then you must comply instead with the provisions of paragraphs (b)(3)(i) and (ii) of this section.

(i) Submit a certification in accordance with §60.5420a(b)(8)(i)(A) in your next annual report, certifying that there is no available control device or process on site and maintain the records in §60.5420a(c)(16)(i) and (ii).

(ii) If you subsequently install a control device or have the ability to route to a process, you are no longer required to comply with paragraph (b)(2)(i) of this section and must submit the information in §60.5420a(b)(8)(ii) in your next annual report and maintain the records in §60.5420a(c)(16)(i), (ii), and (iii). You must be in compliance with the requirements of paragraph (b)(2) of this section within 30 days of startup of the control device or within 30 days of the ability to route to a process.

(4) If the control device available on site is unable to achieve a 95 percent reduction and there is no ability to route the emissions to a process, you must still route the pneumatic pump affected facility's emissions to that existing control device. If you route the pneumatic pump affected facility to a control device installed on site that is designed to achieve less than a 95 percent reduction, you must submit the information specified in §60.5420a(b)(8)(i)(C) in your next annual report and maintain the records in §60.5420a(c)(16)(iii).

(5) If an owner or operator at a non-greenfield site determines, through an engineering assessment, that routing a pneumatic pump to a control device or a process is technically infeasible, the requirements specified in paragraph (b)(5)(i) through (iv) of this section must be met.

(i) The owner or operator shall conduct the assessment of technical infeasibility in accordance with the criteria in paragraph (b)(5)(iii) of this section and have it certified by a qualified professional engineer in accordance with paragraph (b)(5)(ii) of this section.

(ii) The following certification, signed and dated by the qualified professional engineer shall state: "I certify that the assessment of technical infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted and this report was prepared pursuant to the requirements of §60.5393a(b)(5)(iii). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information."

(iii) The assessment of technical feasibility to route emissions from the pneumatic pump to an existing control device onsite or to a process shall include, but is not limited to, safety considerations, distance from the control device, pressure losses and differentials in the closed vent system and the ability of the control device to handle the pneumatic pump emissions which are routed to them. The assessment of technical infeasibility shall be prepared under the direction or supervision of the qualified professional engineer who signs the certification in accordance with paragraph (b)(2)(ii) of this section.

(iv) The owner or operator shall maintain the records §60.5420a(c)(16)(iv).

(6) If the pneumatic pump is routed to a control device or a process and the control device or process is subsequently removed from the location or is no longer available, you are no longer required to be in compliance with the requirements of paragraph (b)(1) or (b)(2) of this section, and instead must comply with paragraph (b)(3) of this section and report the change in next annual report in accordance with §60.5420a(b)(8)(ii).

(c) If you use a control device or route to a process to reduce emissions, you must connect the pneumatic pump affected facility through a closed vent system that meets the requirements of §60.5411a(a) and (d).

(d) You must demonstrate initial compliance with standards that apply to pneumatic pump affected facilities as required by §60.5410a(e).

(e) You must perform the reporting as required by §60.5420a(b)(1) and (8) and the recordkeeping as required by §60.5420a(c)(6) through (10), (16), and (17), as applicable.

(f) Pneumatic pumps at a well site are not subject to the requirements of paragraph (d) and (e) of this section from June 2, 2017, until August 31, 2017.

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

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§60.5395a What VOC standards apply to storage vessel affected facilities?

Except as provided in paragraph (e) of this section, you must comply with the VOC standards in this section for each storage vessel affected facility.

(a) You must comply with the requirements of paragraphs (a)(1) and (2) of this section. After 12 consecutive months of compliance with paragraph (a)(2) of this section, you may continue to comply with paragraph (a)(2) of this section, or you may comply with paragraph (a)(3) of this section, if applicable. If you choose to meet the requirements in paragraph (a)(3) of this section, you are not required to comply with the requirements of paragraph (a)(2) of this section except as provided in paragraphs (a)(3)(i) and (ii) of this section.

(1) Determine the potential for VOC emissions in accordance with §60.5365a(e).

(2) Reduce VOC emissions by 95.0 percent within 60 days after startup. For storage vessel affected facilities receiving liquids pursuant to the standards for well affected facilities in §60.5375a(a)(1)(i) or (ii), you must achieve the required emissions reductions within 60 days after startup of production as defined in §60.5430a.

(3) Maintain the uncontrolled actual VOC emissions from the storage vessel affected facility at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology, and the calculations must be based on the average throughput for the

month. You may no longer comply with this paragraph and must instead comply with paragraph (a)(2) of this section if your storage vessel affected facility meets the conditions specified in paragraphs (a)(3)(i) or (ii) of this section.

(i) If a well feeding the storage vessel affected facility undergoes fracturing or refracturing, you must comply with paragraph (a)(2) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility.

(ii) If the monthly emissions determination required in this section indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, you must comply with paragraph (a)(2) of this section within 30 days of the monthly determination.

(b) *Control requirements.* (1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce VOC emissions from your storage vessel affected facility, you must equip the storage vessel with a cover that meets the requirements of §60.5411a(b) and is connected through a closed vent system that meets the requirements of §60.5411a(c) and (d), and you must route emissions to a control device that meets the conditions specified in §60.5412a(c) or (d). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) If you use a floating roof to reduce emissions, you must meet the requirements of §60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

(c) Requirements for storage vessel affected facilities that are removed from service or returned to service. If you remove a storage vessel affected facility from service, you must comply with paragraphs (c)(1) through (3) of this section. A storage vessel is not an affected facility under this subpart for the period that it is removed from service.

(1) For a storage vessel affected facility to be removed from service, you must comply with the requirements of paragraphs (c)(1)(i) and (ii) of this section.

(i) You must completely empty and degas the storage vessel, such that the storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(ii) You must submit a notification as required in §60.5420a(b)(6)(v) in your next annual report, identifying each storage vessel affected facility removed from service during the reporting period and the date of its removal from service.

(2) If a storage vessel identified in paragraph (c)(1)(ii) of this section is returned to service, you must determine its affected facility status as provided in §60.5365a(e).

(3) For each storage vessel affected facility returned to service during the reporting period, you must submit a notification in your next annual report as required in §60.5420a(b)(6)(vi), identifying each storage vessel affected facility and the date of its return to service.

(d) Compliance, notification, recordkeeping, and reporting. You must comply with paragraphs (d)(1) through (3) of this section.

(1) You must demonstrate initial compliance with standards as required by §60.5410a(h) and (i).

(2) You must demonstrate continuous compliance with standards as required by §60.5415a(e)(3).

(3) You must perform the required reporting as required by §60.5420a(b)(1) and (6) and the recordkeeping as required by §60.5420a(c)(5) through (8), (12) through (14), and (17), as applicable.

(e) *Exemptions.* This subpart does not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, and 40 CFR part 63, subparts G, CC, HH, or WW.

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§60.5397a What fugitive emissions GHG and VOC standards apply to the affected facility which is the collection of fugitive emissions components at a well site and the affected facility which is the collection of fugitive emissions components at a compressor station?

For each affected facility under §60.5365a(i) and (j), you must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with the requirements of paragraphs (a) through (j) of this section. These requirements are independent of the closed vent system and cover requirements in §60.5411a.

(a) You must monitor all fugitive emission components, as defined in §60.5430a, in accordance with paragraphs (b) through (g) of this section. You must repair all sources of fugitive emissions in accordance with paragraph (h) of this section. You must keep records in accordance with paragraph (i) of this section and report in accordance with paragraph (j) of this section. For purposes of this section, fugitive emissions are defined as: Any visible emission from a fugitive emissions component observed using optical gas imaging or an instrument reading of 500 ppm or greater using Method 21.

(b) You must develop an emissions monitoring plan that covers the collection of fugitive emissions components at well sites and compressor stations within each company-defined area in accordance with paragraphs (c) and (d) of this section.

(c) Fugitive emissions monitoring plans must include the elements specified in paragraphs (c)(1) through (8) of this section, at a minimum.

(1) Frequency for conducting surveys. Surveys must be conducted at least as frequently as required by paragraphs (f) and (g) of this section.

(2) Technique for determining fugitive emissions (*i.e.*, Method 21 at 40 CFR part 60, appendix A-7, or optical gas imaging).

(3) Manufacturer and model number of fugitive emissions detection equipment to be used.

(4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (h) of this section at a minimum.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) If you are using optical gas imaging, your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.

(i) Verification that your optical gas imaging equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification and may either be performed by the facility, by the manufacturer, or by a third party. For the purposes of complying with the fugitives emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.

(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.

(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤ 60 g/hr from a quarter inch diameter orifice.

(ii) Procedure for a daily verification check.

(iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

(iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

(v) Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (e.g., steam).

(vi) Training and experience needed prior to performing surveys.

(vii) Procedures for calibration and maintenance. At a minimum, procedures must comply with those recommended by the manufacturer.

(8) If you are using Method 21 of appendix A-7 of this part, your plan must also include the elements specified in paragraphs (c)(8)(i) and (ii) of this section. For the purposes of complying with the fugitive emissions monitoring program using Method 21 a fugitive emission is defined as an instrument reading of 500 ppm or greater.

(i) Verification that your monitoring equipment meets the requirements specified in Section 6.0 of Method 21 at 40 CFR part 60, appendix A-7. For purposes of instrument capability, the fugitive emissions definition shall be 500 ppm or greater methane using a FID-based instrument. If you wish to use an analyzer other than a FID-based instrument, you must develop a site-specific fugitive emission definition that would be equivalent to 500 ppm methane using a FID-based instrument (*e.g.*, 10.6 eV PID with a specified isobutylene concentration as the fugitive emission definition would provide equivalent response to your compound of interest).

(ii) Procedures for conducting surveys. At a minimum, the procedures shall ensure that the surveys comply with the relevant sections of Method 21 at 40 CFR part 60, appendix A-7, including Section 8.3.1.

(d) Each fugitive emissions monitoring plan must include the elements specified in paragraphs (d)(1) through (4) of this section, at a minimum, as applicable.

(1) Sitemap.

(2) A defined observation path that ensures that all fugitive emissions components are within sight of the path. The observation path must account for interferences.

(3) If you are using Method 21, your plan must also include a list of fugitive emissions components to be monitored and method for determining location of fugitive emissions components to be monitored in the field (*e.g.* tagging, identification on a process and instrumentation diagram, etc.).

(4) Your plan must also include the written plan developed for all of the fugitive emission components designated as difficult-to-monitor in accordance with paragraph (g)(3)(i) of this section, and the written plan for fugitive emission components designated as unsafe-to-monitor in accordance with paragraph (g)(3)(ii) of this section.

(e) Each monitoring survey shall observe each fugitive emissions component, as defined in §60.5430a, for fugitive emissions.

(f)(1) You must conduct an initial monitoring survey within 60 days of the startup of production, as defined in §60.5430a, for each collection of fugitive emissions components at a new well site or by June 3, 2017, whichever is later. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within 60 days of the first day of production for each collection of fugitive emission components after the modification or by June 3, 2017, whichever is later. Notwithstanding the preceding deadlines, for each collection of fugitive emissions components at a well site located on the Alaskan North Slope, as defined in §60.5430a, that starts up production between September and March, you must conduct an initial monitoring survey within 6 months of the startup of production for a new well site, within 6 months of the first day of production after a modification of the collection of fugitive emission components, or by the following June 30, whichever is later.

(2) You must conduct an initial monitoring survey within 60 days of the startup of a new compressor station for each new collection of fugitive emissions components at the new compressor station or by June 3, 2017, whichever is later. For a modified collection of fugitive components at a compressor station, the initial monitoring survey must be conducted within 60 days of the modification or by June 3, 2017, whichever is later.

(g) A monitoring survey of each collection of fugitive emissions components at a well site or at a compressor station must be performed at the frequencies specified in paragraphs (g)(1) and (2) of this section, with the exceptions noted in paragraphs (g)(3) and (4) of this section.

(1) Except as provided herein, a monitoring survey of each collection of fugitive emissions components at a well site within a company-defined area must be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys must be conducted at least 4 months apart. A monitoring survey of each collection of fugitive emissions components at a well site located on the Alaskan North Slope must be conducted at least annually. Consecutive annual monitoring surveys must be conducted at least 9 months apart.

(2) A monitoring survey of the collection of fugitive emissions components at a compressor station within a company-defined area must be conducted at least quarterly after the initial survey. Consecutive quarterly monitoring surveys must be conducted at least 60 days apart.

(3) Fugitive emissions components that cannot be monitored without elevating the monitoring personnel more than 2 meters above the surface may be designated as difficult-to-monitor. Fugitive emissions components that are designated difficult-to-monitor must meet the specifications of paragraphs (g)(3)(i) through (iv) of this section.

(i) A written plan must be developed for all of the fugitive emissions components designated difficult-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by paragraphs (b), (c), and (d) of this section.

(ii) The plan must include the identification and location of each fugitive emissions component designated as difficult-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as difficult-to-monitor is difficult-to-monitor.

(iv) The plan must include a schedule for monitoring the difficult-to-monitor fugitive emissions components at least once per calendar year.

(4) Fugitive emissions components that cannot be monitored because monitoring personnel would be exposed to immediate danger while conducting a monitoring survey may be designated as unsafe-to-monitor. Fugitive emissions components that are designated unsafe-to-monitor must meet the specifications of paragraphs (g)(4)(i) through (iv) of this section.

(i) A written plan must be developed for all of the fugitive emissions components designated unsafe-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by paragraphs (b), (c), and (d) of this section.

(ii) The plan must include the identification and location of each fugitive emissions component designated as unsafe-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as unsafe-to-monitor is unsafe-to-monitor.

(iv) The plan must include a schedule for monitoring the fugitive emissions components designated as unsafe-to-monitor.

(5) The requirements of paragraph (g)(2) of this section are waived for any collection of fugitive emissions components at a compressor station located within an area that has an average calendar month temperature below 0 °Fahrenheit for two of three consecutive calendar months of a quarterly monitoring period. The calendar month temperature average for each month within the quarterly monitoring period must be determined using historical monthly average temperatures over the previous three years as reported by a National Oceanic and Atmospheric Administration source or other source approved by the Administrator. The requirements of paragraph (g)(2) of this section shall not be waived for two consecutive quarterly monitoring periods.

(h) Each identified source of fugitive emissions shall be repaired or replaced in accordance with paragraphs (h)(1) and (2) of this section. For fugitive emissions components also subject to the repair provisions of §§60.5416a(b)(9) through (12) and (c)(4) through (7), those provisions apply instead to those closed vent system and covers, and the repair provisions of paragraphs (h)(1) and (2) of this section do not apply to those closed vent systems and covers.

(1) Each identified source of fugitive emissions shall be repaired or replaced as soon as practicable, but no later than 30 calendar days after detection of the fugitive emissions.

(2) If the repair or replacement is technically infeasible, would require a vent blowdown, a compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next scheduled compressor station shutdown, well shutdown, well shut-in, after a planned vent blowdown or within 2 years, whichever is earlier.

(3) Each repaired or replaced fugitive emissions component must be resurveyed as soon as practicable, but no later than 30 days after being repaired, to ensure that there are no fugitive emissions.

(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using either Method 21 or optical gas imaging within 30 days of finding such fugitive emissions.

(ii) For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph must be taken of that component or the component must be tagged for identification purposes. The digital photograph must include the date that the photograph was taken, must clearly identify the component by location within the site (*e.g.*, the latitude and longitude of the component or by other descriptive landmarks visible in the picture).

(iii) Operators that use Method 21 to resurvey the repaired fugitive emissions components are subject to the resurvey provisions specified in paragraphs (h)(3)(iii)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the Method 21 instrument indicates a concentration of less than 500 ppm above background or when no soap bubbles are observed when the alternative screening procedures specified in section 8.3.3 of Method 21 are used.

(B) Operators must use the Method 21 monitoring requirements specified in paragraph (c)(8)(ii) of this section or the alternative screening procedures specified in section 8.3.3 of Method 21.

(iv) Operators that use optical gas imaging to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (h)(3)(iv)(A) and (B) of this section.

(A) A fugitive emissions component is repaired when the optical gas imaging instrument shows no indication of visible emissions.

(B) Operators must use the optical gas imaging monitoring requirements specified in paragraph (c)(7) of this section.

(i) Records for each monitoring survey shall be maintained as specified §60.5420a(c)(15).

(j) Annual reports shall be submitted for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station that

include the information specified in §60.5420a(b)(7). Multiple collection of fugitive emissions components at a well site or at a compressor station may be included in a single annual report.

[81 FR 35898, June 3, 2016, as amended at 83 FR 10638, Mar. 12, 2018]

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§60.5398a What are the alternative means of emission limitations for GHG and VOC from well completions, reciprocating compressors, the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in GHG (in the form of a limitation on emission of methane) and VOC emissions at least equivalent to the reduction in GHG and VOC emissions achieved under §§60.5375a, 60.5385a, and 60.5397a, the Administrator will publish, in the FEDERAL REGISTER, a notice permitting the use of that alternative means for the purpose of compliance with §§60.5375a, 60.5385a, and 60.5397a. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities.

(d) Determination of equivalence to the design, equipment, work practice or operational requirements of this section will be evaluated by the following guidelines:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months to demonstrate the equivalence of the alternative means of emission limitation. The application must include the following information:

(i) A description of the technology or process.

(ii) The monitoring instrument and measurement technology or process.

(iii) A description of performance based procedures (*i.e.*, method) and data quality indicators for precision and bias; the method detection limit of the technology or process.

(iv) For affected facilities under §60.5397a, the action criteria and level at which a fugitive emission exists.

- (v) Any initial and ongoing quality assurance/quality control measures.
 - (vi) Timeframes for conducting ongoing quality assurance/quality control.
 - (vii) Field data verifying viability and detection capabilities of the technology or process.
 - (viii) Frequency of measurements.
 - (ix) Minimum data availability.
 - (x) Any restrictions for using the technology or process.
 - (xi) Operation and maintenance procedures and other provisions necessary to ensure reduction in methane and VOC emissions at least equivalent to the reduction in methane and VOC emissions achieved under §60.5397a.
 - (xii) Initial and continuous compliance procedures, including recordkeeping and reporting.
- (2) For each determination of equivalency requested, the emission reduction achieved by the design, equipment, work practice or operational requirements shall be demonstrated.
- (3) For each affected facility for which a determination of equivalency is requested, the emission reduction achieved by the alternative means of emission limitation shall be demonstrated.
- (4) Each owner or operator applying for a determination of equivalence to a work practice standard shall commit in writing to work practice(s) that provide for emission reductions equal to or greater than the emission reductions achieved by the required work practice.
- (e) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the FEDERAL REGISTER.
- (f) An application submitted under this section will be evaluated as set forth in paragraphs (f)(1) and (2) of this section.
- (1) The Administrator will compare the demonstrated emission reduction for the alternative means of emission limitation to the demonstrated emission reduction for the design, equipment, work practice or operational requirements and, if applicable, will consider the commitment in paragraph (d) of this section.
- (2) The Administrator may condition the approval of the alternative means of emission limitation on requirements that may be necessary to ensure operation and maintenance to achieve the same emissions reduction as the design, equipment, work practice or operational requirements. (g) Any equivalent means of emission limitations approved under this section shall constitute a required work practice, equipment, design or operational standard within the meaning of section 111(h)(1) of the CAA.

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§60.5400a What equipment leak GHG and VOC standards apply to affected facilities at an onshore natural gas processing plant?

This section applies to the group of all equipment, except compressors, within a process unit.

- (a) You must comply with the requirements of §§60.482-1a(a), (b), and (d), 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in §60.5401a.
- (b) You may elect to comply with the requirements of §§60.483-1a and 60.483-2a, as an alternative.
- (c) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of methane and VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of §60.5402a.
- (d) You must comply with the provisions of §60.485a except as provided in paragraph (f) of this section.
- (e) You must comply with the provisions of §§60.486a and 60.487a except as provided in §§60.5401a, 60.5421a, and 60.5422a.
- (f) You must use the following provision instead of §60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 (incorporated by reference as specified in §60.17) must be used.

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§60.5401a What are the exceptions to the equipment leak GHG and VOC standards for affected facilities at onshore natural gas processing plants?

(a) You may comply with the following exceptions to the provisions of §60.5400a(a) and (b).

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in §60.485a(b) except as provided in §§60.5400a(c) and in paragraph (b)(4) of this section, and 60.482-4a(a) through (c) of subpart VVa of this part.

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9a.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are onsite, instead of within 5 days as specified in paragraph (b)(1) of this section and §60.482-4a(b)(1).

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section may be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of §60.482-5a.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§60.482-2a(a)(1), 60.482-7a(a), 60.482-11a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of §§60.482-2a(a)(1), 60.482-7a(a), 60.482-11a(a), and paragraph (b)(1) of this section.

(f) An owner or operator may use the following provisions instead of §60.485a(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °Celsius (302 °Fahrenheit) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °Celsius (302 °Fahrenheit) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

(g) An owner or operator may use the following provisions instead of §60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A-7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in §60.486a(e)(8). Divide these readings by the initial calibration values for each scale and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

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§60.5402a What are the alternative means of emission limitations for GHG and VOC equipment leaks from onshore natural gas processing plants?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in GHG and VOC emissions at least equivalent to the reduction in GHG and VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the FEDERAL REGISTER, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

(d) An application submitted under paragraph (c) of this section must meet the following criteria:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.

(2) The application must include operation, maintenance and other provisions necessary to assure reduction in methane and VOC emissions at least equivalent to the reduction in methane and VOC emissions achieved under the design, equipment, work practice or operational standard in paragraph (a) of this section by including the information specified in paragraphs (d)(1)(i) through (x) of this section.

(i) A description of the technology or process.

(ii) The monitoring instrument and measurement technology or process.

(iii) A description of performance based procedures (i.e. method) and data quality indicators for precision and bias; the method detection limit of the technology or process.

(iv) The action criteria and level at which a fugitive emission exists.

(v) Any initial and ongoing quality assurance/quality control measures.

(vi) Timeframes for conducting ongoing quality assurance/quality control.

(vii) Field data verifying viability and detection capabilities of the technology or process.

(viii) Frequency of measurements.

(ix) Minimum data availability.

(x) Any restrictions for using the technology or process.

(3) The application must include initial and continuous compliance procedures including recordkeeping and reporting.

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§60.5405a What standards apply to sweetening unit affected facilities at onshore natural gas processing plants?

(a) During the initial performance test required by §60.8(b), you must achieve at a minimum, an SO₂ emission reduction efficiency (Z_i) to be determined from Table 1 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an SO₂ emission reduction efficiency (Z_c) to be determined from Table 2 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

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§60.5406a What test methods and procedures must I use for my sweetening unit affected facilities at onshore natural gas processing plants?

(a) In conducting the performance tests required in §60.8, you must use the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) During a performance test required by §60.8, you must determine the minimum required reduction efficiencies (Z) of SO₂ emissions as required in §60.5405a(a) and (b) as follows:

(1) The average sulfur feed rate (X) must be computed as follows:

$$X = KQ_aY$$

Where:

X = average sulfur feed rate, Mg/D (LT/D).

Q_a = average volumetric flow rate of acid gas from sweetening unit, dscm/day (dscf/day).

Y = average H₂S concentration in acid gas feed from sweetening unit, percent by volume, expressed as a decimal.

K = (32 kg S/kg-mole)/((24.04 dscm/kg-mole)(1000 kg S/Mg)).

= 1.331 × 10⁻³Mg/dscm, for metric units.

= (32 lb S/lb-mole)/((385.36 dscf/lb-mole)(2240 lb S/long ton)).

= 3.707 × 10⁻⁵ long ton/dscf, for English units.

(2) You must use the continuous readings from the process flowmeter to determine the average volumetric flow rate (Q_a) in dscm/day (dscf/day) of the acid gas from the sweetening unit for each run.

(3) You must use the Tutwiler procedure in §60.5408a or a chromatographic procedure following ASTM E260-96 (incorporated by reference as specified in §60.17) to determine the H₂S concentration in the acid gas feed from the sweetening unit (Y). At least one sample per hour (at equally spaced intervals) must be taken during each 4-hour run. The arithmetic mean of all samples must be the average H₂S concentration (Y) on a dry basis for the run. By multiplying the

result from the Tutwiler procedure by 1.62×10^{-3} , the units gr/100 scf are converted to volume percent.

(4) Using the information from paragraphs (b)(1) and (3) of this section, Tables 1 and 2 of this subpart must be used to determine the required initial (Z_i) and continuous (Z_c) reduction efficiencies of SO₂ emissions.

(c) You must determine compliance with the SO₂ standards in §60.5405a(a) or (b) as follows:

(1) You must compute the emission reduction efficiency (R) achieved by the sulfur recovery technology for each run using the following equation:

$$R = (100S)/(S + E)$$

(2) You must use the level indicators or manual soundings to measure the liquid sulfur accumulation rate in the product storage vessels. You must use readings taken at the beginning and end of each run, the tank geometry, sulfur density at the storage temperature, and sample duration to determine the sulfur production rate (S) in kg/hr (lb/hr) for each run.

(3) You must compute the emission rate of sulfur for each run as follows:

$$E = C_e Q_{sd} / K_1$$

Where:

E = emission rate of sulfur per run, kg/hr.

C_e = concentration of sulfur equivalent (SO₂+ reduced sulfur), g/dscm (lb/dscf).

Q_{sd} = volumetric flow rate of effluent gas, dscm/hr (dscf/hr).

K_1 = conversion factor, 1000 g/kg (7000 gr/lb).

(4) The concentration (C_e) of sulfur equivalent must be the sum of the SO₂ and TRS concentrations, after being converted to sulfur equivalents. For each run and each of the test methods specified in this paragraph (c) of this section, you must use a sampling time of at least 4 hours. You must use Method 1 of appendix A-1 of this part to select the sampling site. The sampling point in the duct must be at the centroid of the cross-section if the area is less than 5 m² (54 ft²) or at a point no closer to the walls than 1 m (39 in) if the cross-sectional area is 5 m² or more, and the centroid is more than 1 m (39 in) from the wall.

(i) You must use Method 6 of appendix A-4 of this part to determine the SO₂ concentration. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration must be multiplied by 0.5×10^{-3} to convert the results to sulfur equivalent. In place of Method 6 of appendix A of this part, you may use

ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17).

(ii) You must use Method 15 of appendix A-5 of this part to determine the TRS concentration from reduction-type devices or where the oxygen content of the effluent gas is less than 1.0 percent by volume. The sampling rate must be at least 3 liters/min (0.1 ft³/min) to insure minimum residence time in the sample line. You must take sixteen samples at 15-minute intervals. The arithmetic average of all the samples must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iii) You must use Method 16A of appendix A-6 of this part or Method 15 of appendix A-5 of this part or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17) to determine the reduced sulfur concentration from oxidation-type devices or where the oxygen content of the effluent gas is greater than 1.0 percent by volume. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iv) You must use Method 2 of appendix A-1 of this part to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged. For the moisture content, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

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§60.5407a What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?

(a) If your sweetening unit affected facility is located at an onshore natural gas processing plant and is subject to the provisions of §60.5405a(a) or (b) you must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the following operations information on a daily basis:

(1) The accumulation of sulfur product over each 24-hour period. The monitoring method may incorporate the use of an instrument to measure and record the liquid sulfur production rate, or may be a procedure for measuring and recording the sulfur liquid levels in the storage vessels with a level indicator or by manual soundings, with subsequent calculation of the sulfur production rate based on the tank geometry, stored sulfur density, and elapsed time between

readings. The method must be designed to be accurate within ± 2 percent of the 24-hour sulfur accumulation.

(2) The H_2S concentration in the acid gas from the sweetening unit for each 24-hour period. At least one sample per 24-hour period must be collected and analyzed using the equation specified in §60.5406a(b)(1). The Administrator may require you to demonstrate that the H_2S concentration obtained from one or more samples over a 24-hour period is within ± 20 percent of the average of 12 samples collected at equally spaced intervals during the 24-hour period. In instances where the H_2S concentration of a single sample is not within ± 20 percent of the average of the 12 equally spaced samples, the Administrator may require a more frequent sampling schedule.

(3) The average acid gas flow rate from the sweetening unit. You must install and operate a monitoring device to continuously measure the flow rate of acid gas. The monitoring device reading must be recorded at least once per hour during each 24-hour period. The average acid gas flow rate must be computed from the individual readings.

(4) The sulfur feed rate (X). For each 24-hour period, you must compute X using the equation specified in §60.5406a(b)(1).

(5) The required sulfur dioxide emission reduction efficiency for the 24-hour period. You must use the sulfur feed rate and the H_2S concentration in the acid gas for the 24-hour period, as applicable, to determine the required reduction efficiency in accordance with the provisions of §60.5405a(b).

(b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows:

(1) A continuous monitoring system to measure the total sulfur emission rate (E) of SO_2 in the gases discharged to the atmosphere. The SO_2 emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of §60.5405a(b) will be between 30 percent and 70 percent of the measurement range of the instrument system.

(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with §60.5405a(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ± 1 percent of the temperature being measured.

(3) When performance tests are conducted under the provision of §60.8 to demonstrate compliance with the standards under §60.5405a, the temperature of the gas leaving the incinerator combustion zone must be determined using the monitoring device. If the volumetric

ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as SO₂) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate level determined during the most recent performance test to ensure the sulfur compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under §60.8.

(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds as required in paragraph (d) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).

(c) Where compliance is achieved through the use of a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as SO₂ equivalent in the gases discharged to the atmosphere. The SO₂ equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of §60.5405a(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.

(d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock interval. The 24-hour interval may begin and end at any selected clock time, but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in §60.5406a(c)(1).

(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S.

(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average.

(e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of H₂S expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:



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Where:

R = The sulfur dioxide removal efficiency achieved during the 24-hour period, percent.

K₂ = Conversion factor, 0.02400 Mg/D per kg/hr (0.01071 LT/D per lb/hr).

S = The sulfur production rate during the 24-hour period, kg/hr (lb/hr).

X = The sulfur feed rate in the acid gas, Mg/D (LT/D).

(f) The monitoring devices required in paragraphs (b)(1), (b)(3) and (c) of this section must be calibrated at least annually according to the manufacturer's specifications, as required by §60.13(b).

(g) The continuous emission monitoring systems required in paragraphs (b)(1), (b)(3), and (c) of this section must be subject to the emission monitoring requirements of §60.13 of the General Provisions. For conducting the continuous emission monitoring system performance evaluation required by §60.13(c), Performance Specification 2 of appendix B of this part must apply, and Method 6 of appendix A-4 of this part must be used for systems required by paragraph (b) of this section. In place of Method 6 of appendix A-4 of this part, ASME PTC 19.10-1981 (incorporated by reference—see §60.17) may be used.

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§60.5408a What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?

The Tutwiler procedure may be found in the Gas Engineers Handbook, Fuel Gas Engineering practices, The Industrial Press, 93 Worth Street, New York, NY, 1966, First Edition, Second Printing, page 6/25 (Docket A-80-20-A, Entry II-I-67).

(a) When an instantaneous sample is desired and H₂S concentration is 10 grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than 10 grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine.

(b) *Apparatus.* (See Figure 1 of this subpart.) A 100 or 500 ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top that connect either with inlet tubulature or glass-stoppered cylinder, 10 ml capacity, graduated in 0.1 ml subdivision; rubber tubing connecting burette with leveling bottle.

(c) *Reagents.* (1) Iodine stock solution, 0.1N. Weight 12.7 g iodine, and 20 to 25 g cp potassium iodide (KI) for each liter of solution. Dissolve KI in as little water as necessary; dissolve iodine in concentrated KI solution, make up to proper volume, and store in glass-stoppered brown glass bottle.

(2) Standard iodine solution, 1 ml=0.001771 g I. Transfer 33.7 ml of above 0.1N stock solution into a 250 ml volumetric flask; add water to mark and mix well. Then, for 100 ml sample of gas, 1 ml of standard iodine solution is equivalent to 100 grains H_2S per cubic feet of gas.

(3) *Starch solution.* Rub into a thin paste about one teaspoonful of wheat starch with a little water; pour into about a pint of boiling water; stir; let cool and decant off clear solution. Make fresh solution every few days.

(d) *Procedure.* Fill leveling bulb with starch solution. Raise (L), open cock (G), open (F) to (A), and close (F) when solutions starts to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine through (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D.

(e) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then,

Grains H_2S per 100 cubic foot of gas = 100 (D-C)

(f) Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with H_2S -free gas or air, is required.



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§60.5410a How do I demonstrate initial compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, collection of fugitive emissions components at a compressor station, and equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (j) of this section. The initial compliance period begins on August 2, 2016, or upon initial startup, whichever is later, and ends no later than 1 year after the initial startup date for your affected facility or no later than 1 year after August 2, 2016. The initial compliance period may be less than one full year.

(a) To achieve initial compliance with the methane and VOC standards for each well completion operation conducted at your well affected facility you must comply with paragraphs (a)(1) through (4) of this section.

(1) You must submit the notification required in §60.5420a(a)(2).

(2) You must submit the initial annual report for your well affected facility as required in §60.5420a(b)(1) and (2).

(3) You must maintain a log of records as specified in §60.5420a(c)(1)(i) through (iv), as applicable, for each well completion operation conducted during the initial compliance period. If you meet the exemption for wells with a GOR less than 300 scf per stock barrel of oil produced, you do not have to maintain the records in §60.5420a(c)(1)(i) through (iv) and must maintain the record in §60.5420a(c)(1)(vi).

(4) For each well affected facility subject to both §60.5375a(a)(1) and (3), as an alternative to retaining the records specified in §60.5420a(c)(1)(i) through (iv), you may maintain records in accordance with §60.5420a(c)(1)(v) of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each well completion operation that occurred during the initial compliance period. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment

connected and operating at each well completion operation with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(b)(1) To achieve initial compliance with standards for your centrifugal compressor affected facility you must reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater as required by §60.5380a(a) and as demonstrated by the requirements of §60.5413a.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411a(b) that is connected through a closed vent system that meets the requirements of §60.5411a(a) and (d) and is routed to a control device that meets the conditions specified in §60.5412a(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(3) You must conduct an initial performance test as required in §60.5413a within 180 days after initial startup or by August 2, 2016, whichever is later, and you must comply with the continuous compliance requirements in §60.5415a(b).

(4) You must conduct the initial inspections required in §60.5416a(a) and (b).

(5) You must install and operate the continuous parameter monitoring systems in accordance with §60.5417a(a) through (g), as applicable.

(6)]Reserved]

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in §60.5420a(b)(1) and (3).

(8) You must maintain the records as specified in §60.5420a(c)(2), (6) through (11), and (17), as applicable.

(c) To achieve initial compliance with the standards for each reciprocating compressor affected facility you must comply with paragraphs (c)(1) through (4) of this section.

(1) If complying with §60.5385a(a)(1) or (2), during the initial compliance period, you must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement.

(2) If complying with §60.5385a(a)(3), you must operate the rod packing emissions collection system under negative pressure and route emissions to a process through a closed vent system that meets the requirements of §60.5411a(a) and (d).

(3) You must submit the initial annual report for your reciprocating compressor as required in §60.5420a(b)(1) and (4).

(4) You must maintain the records as specified in §60.5420a(c)(3) for each reciprocating compressor affected facility.

(d) To achieve initial compliance with methane and VOC emission standards for your pneumatic controller affected facility you must comply with the requirements specified in paragraphs (d)(1) through (6) of this section, as applicable.

(1) You must demonstrate initial compliance by maintaining records as specified in §60.5420a(c)(4)(ii) of your determination that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required as specified in §60.5390a(b)(1) or (c)(1).

(2) If you own or operate a pneumatic controller affected facility located at a natural gas processing plant, your pneumatic controller must be driven by a gas other than natural gas, resulting in zero natural gas emissions.

(3) If you own or operate a pneumatic controller affected facility located other than at a natural gas processing plant, the controller manufacturer's design specifications for the controller must indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.

(4) You must tag each new pneumatic controller affected facility according to the requirements of §60.5390a(b)(2) or (c)(2).

(5) You must include the information in paragraph (d)(1) of this section and a listing of the pneumatic controller affected facilities specified in paragraphs (d)(2) and (3) of this section in the initial annual report submitted for your pneumatic controller affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of §60.5420a(b)(1) and (5).

(6) You must maintain the records as specified in §60.5420a(c)(4) for each pneumatic controller affected facility.

(e) To achieve initial compliance with emission standards for your pneumatic pump affected facility you must comply with the requirements specified in paragraphs (e)(1) through (7) of this section, as applicable.

(1) If you own or operate a pneumatic pump affected facility located at a natural gas processing plant, your pneumatic pump must be driven by a gas other than natural gas, resulting in zero natural gas emissions.

(2) If you own or operate a pneumatic pump affected facility not located at a natural gas processing plant, you must reduce emissions in accordance §60.5393a(b)(1) or (b)(2), and you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of §60.5411a(a) and (d).

(3) If you own or operate a pneumatic pump affected facility not located at a natural gas processing plant and there is no control device or process available on site, you must submit the certification in 60.5420a(b)(8)(i)(A).

(4) If you own or operate a pneumatic pump affected facility not located at a natural gas processing plant or a greenfield site, and you are unable to route to an existing control device due to technical infeasibility, and you are unable to route to a process, you must submit the certification in §60.5420a(b)(8)(i)(B).

(5) If you own or operate a pneumatic pump affected facility not located other than at a natural gas processing plant and you reduce emissions in accordance with §60.5393a(b)(4), you must collect the pneumatic pump emissions through a closed vent system that meets the requirements of §60.5411a(c) and (d).

(6) You must submit the initial annual report for your pneumatic pump affected facility required in §60.5420a(b)(1) and (8).

(7) You must maintain the records as specified in §60.5420a(c)(6), (8) through (10), (16), and (17), as applicable, for each pneumatic pump affected facility.

(8) Pneumatic pump affected facilities at a well are not subject to the requirements of (e)(6) and (7) of this section from June 2, 2017, until August 31, 2017.

(f) For affected facilities at onshore natural gas processing plants, initial compliance with the methane and VOC standards is demonstrated if you are in compliance with the requirements of §60.5400a.

(g) For sweetening unit affected facilities at onshore natural gas processing plants, initial compliance is demonstrated according to paragraphs (g)(1) through (3) of this section.

(1) To determine compliance with the standards for SO₂ specified in §60.5405a(a), during the initial performance test as required by §60.8, the minimum required sulfur dioxide emission reduction efficiency (Z_i) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology as specified in paragraphs (g)(1)(i) and (ii) of this section.

(i) If $R \geq Z_i$, your affected facility is in compliance.

(ii) If $R < Z_i$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in §60.5406a(c)(1).

(3) You must submit the results of paragraphs (g)(1) and (2) of this section in the initial annual report submitted for your sweetening unit affected facilities at onshore natural gas processing plants.

(h) For each storage vessel affected facility, you must comply with paragraphs (h)(1) through (6) of this section. You must demonstrate initial compliance by August 2, 2016, or within 60 days after startup, whichever is later.

(1) You must determine the potential VOC emission rate as specified in §60.5365a(e).

(2) You must reduce VOC emissions in accordance with §60.5395a(a).

(3) If you use a control device to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of §60.5411a(b) and is connected through a closed vent system that meets the requirements of §60.5411a(c) and (d) to a control device that meets the conditions specified in §60.5412a(d) within 60 days after startup for storage vessels constructed, modified or reconstructed at well sites with no other wells in production, or upon startup for storage vessels constructed, modified or reconstructed at well sites with one or more wells already in production.

(4) You must conduct an initial performance test as required in §60.5413a within 180 days after initial startup or within 180 days of August 2, 2016, whichever is later, and you must comply with the continuous compliance requirements in §60.5415a(e).

(5) You must submit the information required for your storage vessel affected facility in your initial annual report as specified in §60.5420a(b)(1) and (6).

(6) You must maintain the records required for your storage vessel affected facility, as specified in §60.5420a(c)(5) through (8), (12) through (14), and (17), as applicable, for each storage vessel affected facility.

(i) For each storage vessel affected facility that complies by using a floating roof, you must submit a statement that you are complying with §60.112(b)(a)(1) or (2) in accordance with §60.5395a(b)(2) with the initial annual report specified in §60.5420a(b).

(j) To achieve initial compliance with the fugitive emission standards for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, you must comply with paragraphs (j)(1) through (5) of this section.

(1) You must develop a fugitive emissions monitoring plan as required in §60.5397a(b)(c), and (d).

(2) You must conduct an initial monitoring survey as required in §60.5397a(f).

(3) You must maintain the records specified in §60.5420a(c)(15).

(4) You must repair each identified source of fugitive emissions for each affected facility as required in §60.5397a(h).

(5) You must submit the initial annual report for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station compressor station as required in §60.5420a(b)(1) and (7).

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

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§60.5411a What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing emissions from centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels?

You must meet the applicable requirements of this section for each cover and closed vent system used to comply with the emission standards for your centrifugal compressor wet seal degassing systems, reciprocating compressors, pneumatic pumps and storage vessels except as provided in paragraph (e) of this section.

(a) Closed vent system requirements for reciprocating compressors, centrifugal compressor wet seal degassing systems and pneumatic pumps.

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the reciprocating compressor rod packing emissions collection system, the wet seal fluid degassing system or pneumatic pump to a control device or to a process. For reciprocating and centrifugal compressors, the closed vent system must route all gases, vapors, and fumes to a control device that meets the requirements specified in §60.5412a(a) through (c).

(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by §60.5416a(b).

(3) You must meet the requirements specified in paragraphs (a)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device.

(i) Except as provided in paragraph (a)(3)(ii) of this section, you must comply with either paragraph (a)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings as specified in §60.5416a(a)(4)(i) and sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control

device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420a(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (a)(3)(i) of this section.

(b) Cover requirements for storage vessels and centrifugal compressor wet seal fluid degassing systems.

(1) The cover and all openings on the cover (*e.g.*, access hatches, sampling ports, pressure relief devices and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or wet seal fluid degassing system.

(2) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph (a) or (c), and (d), of this section to a control device or to a process.

(3) Each storage vessel thief hatch shall be equipped, maintained and operated with a weighted mechanism or equivalent, to ensure that the lid remains properly seated and sealed under normal operating conditions, including such times when working, standing/breathing, and flash emissions may be generated. You must select gasket material for the hatch based on composition of the fluid in the storage vessel and weather conditions.

(c) Closed vent system requirements for storage vessel affected facilities using a control device or routing emissions to a process.

(1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the storage vessel to a control device that meets the requirements specified in §60.5412a(c) and (d), or to a process.

(2) You must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual and auditory inspections.

(3) You must meet the requirements specified in paragraphs (c)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process.

(i) Except as provided in paragraph (c)(3)(ii) of this section, you must comply with either paragraph (c)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420a(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (c)(3)(i) of this section.

(d) Closed vent systems requirements for centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels using a control device or routing emissions to a process.

(1) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all emissions from the storage vessel are routed to the control device and that the control device is of sufficient design and capacity to accommodate all emissions from the affected facility and have it certified by a qualified professional engineer in accordance with paragraphs (d)(1)(i) and (ii) of this section.

(i) You must provide the following certification, signed and dated by the qualified professional engineer: "I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted and this report was prepared pursuant to the requirements of subpart OOOOa of 40 CFR part 60. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information."

(ii) The assessment shall be prepared under the direction or supervision of the qualified professional engineer who signs the certification in paragraph (d)(1)(i) of this section.

(2) [Reserved]

(e) Pneumatic pump affected facilities at a well site are not subject to the requirements of paragraph (a) of this section from June 2, 2017, until August 31, 2017.

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

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§60.5412a What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my centrifugal compressor, and storage vessel affected facilities?

You must meet the applicable requirements of this section for each control device used to comply with the emission standards for your centrifugal compressor affected facility, or storage vessel affected facility.

(a) Each control device used to meet the emission reduction standard in §60.5380a(a)(1) for your centrifugal compressor affected facility must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a control device model tested under §60.5413a(d), which meets the criteria in §60.5413a(d)(11) and meet the continuous compliance requirements in §60.5413a(e).

(1) Each combustion device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section.

(i) You must reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413a(b), with the exceptions noted in §60.5413a(a).

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of §60.5413a(b), with the exceptions noted in §60.5413a(a).

(iii) You must operate at a minimum temperature of 760 °Celsius, provided the control device has demonstrated, during the performance test conducted under §60.5413a(b), that combustion zone temperature is an indicator of destruction efficiency.

(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(2) Each vapor recovery device (*e.g.*, carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413a(b). As an alternative to the performance testing requirements, you may demonstrate initial compliance by conducting a design analysis for vapor recovery devices according to the requirements of §60.5413a(c).

(3) You must design and operate a flare in accordance with the requirements of §60.18(b), and you must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(b) You must operate each control device installed on your centrifugal compressor affected facility in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system affected facility as required under §60.5380a(a)(1) through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

(2) For each control device monitored in accordance with the requirements of §60.5417a(a) through (g), you must demonstrate compliance according to the requirements of §60.5415a(b)(2), as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) or (d)(2) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (c)(1) or (2) of this section.

(1) Following the initial startup of the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to §60.5413a(c)(2) or (3) or according to the design required in paragraph (d)(2) of this section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in §60.5420a(c)(10) and (12).

(2) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(2)(i) through (vi) of this section.

(i) Regenerate or reactivate the spent carbon in a unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(ii) Regenerate or reactivate the spent carbon in a unit equipped with an operating organic air emission controls in accordance with an emissions standard for VOC under another subpart in 40 CFR part 63 or this part.

(iii) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(iv) Burn the spent carbon in a hazardous waste boiler or industrial furnace for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(v) Burn the spent carbon in an industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(vi) Burn the spent carbon in an industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(d) Each control device used to meet the emission reduction standard in §60.5395a(a)(2) for your storage vessel affected facility must be installed according to paragraphs (d)(1) through (4) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a control device model tested under §60.5413a(d), which meets the criteria in §60.5413a(d)(11) and meet the continuous compliance requirements in §60.5413a(e).

(1) For each combustion control device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) you must meet the requirements in paragraphs (d)(1)(i) through (iv) of this section.

(i) Ensure that each enclosed combustion control device is maintained in a leak free condition.

(ii) Install and operate a continuous burning pilot flame.

(iii) Operate the combustion control device with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period. A visible emissions test using section 11 of EPA Method 22 of appendix A-7 of this part must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes. Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection. Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A-7 of this part visual observation as described in this paragraph.

(iv) Each enclosed combustion control device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (A) through (D) of this section.

(A) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413a(b).

(B) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of §60.5413a(b).

(C) You must operate at a minimum temperature of 760 °Celsius, provided the control device has demonstrated, during the performance test conducted under §60.5413a(b), that combustion zone temperature is an indicator of destruction efficiency.

(D) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(2) Each vapor recovery device (*e.g.*, carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater. A carbon replacement schedule must be included in the design of the carbon adsorption system.

(3) You must design and operate a flare in accordance with the requirements of §60.18(b), and you must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(4) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

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§60.5413a What are the performance testing procedures for control devices used to demonstrate compliance at my centrifugal compressor and storage vessel affected facilities?

This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your centrifugal compressor affected facility or storage vessel affected facility. You must demonstrate that a control device achieves the performance requirements of §60.5412a(a)(1) or (2) or (d)(1) or (2) using the performance test methods and procedures specified in this section. For condensers and carbon adsorbers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section. In addition, this section contains the requirements for enclosed combustion control device performance tests conducted by the manufacturer applicable to storage vessel and centrifugal compressor affected facilities.

(a) *Performance test exemptions.* You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.

(1) A flare that is designed and operated in accordance with §60.18(b). You must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H; you have submitted a Notification of Compliance under 40 CFR 63.1207(j) and comply with the requirements of 40 CFR part 63, subpart EEE; or you comply with 40 CFR part 63, subpart EEE and will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in §60.5420(b)(9) for submitting the initial performance test report.

(5) A hazardous waste incinerator for which you have submitted a Notification of Compliance under 40 CFR 63.1207(j), or for which you will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in §60.5420a(b)(9) for submitting the initial performance test report, and you comply with the requirements of 40 CFR part 63, subpart EEE.

(6) A performance test is waived in accordance with §60.8(b).

(7) A control device whose model can be demonstrated to meet the performance requirements of §60.5412a(a)(1) or (d)(1) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) *Test methods and procedures.* You must use the test methods and procedures specified in paragraphs (b)(1) through (5) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of §60.5412a(a)(1) or (2) or (d)(1) or (2). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) of this section. Each performance test must consist of a minimum of 3 test runs. Each run must be at least 1 hour long.

(1) You must use Method 1 or 1A of appendix A-1 of this part, as appropriate, to select the sampling sites specified in paragraphs (b)(1)(i) and (ii) of this section. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(i) Sampling sites must be located at the inlet of the first control device and at the outlet of the final control device to determine compliance with a control device percent reduction requirement.

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with a TOC exhaust gas concentration limit.

(2) You must determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D of appendix A-2 of this part, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in §60.5412a(a)(1)(i), (a)(2) or (d)(1)(iv)(A), you must use Method 25A of appendix A-7 of this part. You must use Method 4 of appendix A-3 of this part to convert the Method 25A results to a dry basis. You must use the procedures in paragraphs (b)(3)(i) through (iii) of this section to calculate percent reduction efficiency.

(i) You must compute the mass rate of TOC using the following equations:

$$E_i = K_2 C_i M_p Q_i$$

$$E_o = K_2 C_o M_p Q_o$$

Where:

E_i , E_o = Mass rate of TOC at the inlet and outlet of the control device, respectively, dry basis, kilograms per hour.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 °Celsius.

C_i , C_o = Concentration of TOC, as propane, of the gas stream as measured by Method 25A at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M_p = Molecular weight of propane, 44.1 gram/gram-mole.

Q_i , Q_o = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

(ii) You must calculate the percent reduction in TOC as follows:



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Where:

R_{cd} = Control efficiency of control device, percent.

E_i = Mass rate of TOC at the inlet to the control device as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

E_o = Mass rate of TOC at the outlet of the control device, as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

(iii) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC across the device by comparing the TOC in all combusted vent streams and primary and secondary fuels with the TOC exiting the device, respectively.

(4) You must use Method 25A of appendix A-7 of this part to measure TOC, as propane, to determine compliance with the TOC exhaust gas concentration limit specified in §60.5412a(a)(1)(ii) or (d)(1)(iv)(B). You may also use Method 18 of appendix A-6 of this part to measure methane and ethane. You may subtract the measured concentration of methane and ethane from the Method 25A measurement to demonstrate compliance with the concentration limit. You must determine the concentration in parts per million by volume on a wet basis and correct it to 3 percent oxygen, using the procedures in paragraphs (b)(4)(i) through (iii) of this section.

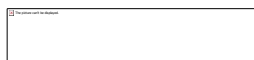
(i) If you use Method 18 to determine methane and ethane, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run. You must determine the average methane and ethane concentration per run. The samples must be taken during the same time as the Method 25A sample.

(ii) You may subtract the concentration of methane and ethane from the Method 25A TOC, as propane, concentration for each run.

(iii) You must correct the TOC concentration (minus methane and ethane, if applicable) to 3 percent oxygen as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B of appendix A-2 of this part, ASTM D6522-00 (Reapproved 2005), or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration.

(B) You must correct the TOC concentration for percent oxygen as follows:



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Where:

C_c = TOC concentration, as propane, corrected to 3 percent oxygen, parts per million by volume on a wet basis.

C_m = TOC concentration, as propane, (minus methane and ethane, if applicable), parts per million by volume on a wet basis.

$\%O_{2m}$ = Concentration of oxygen, percent by volume as measured, wet.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after initial startup for your affected facility. You must submit the performance test results as required in §60.5420a(b)(9).

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests except as specified in paragraphs (b)(5)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in §60.5420a(b)(9).

(A) A control device whose model is tested under, and meets the criteria of paragraph (d) of this section. For centrifugal compressor affected facilities, if you do not continuously monitor the gas flow rate in accordance with §60.5417a(d)(1)(viii), then you must comply with the periodic performance testing requirements of paragraph (b)(5)(ii).

(B) A combustion control device tested under paragraph (b) of this section that meets the outlet TOC performance level specified in §60.5412a(a)(1)(ii) or (d)(1)(iv)(B) and that establishes a correlation between firebox or combustion chamber temperature and the TOC performance level. For centrifugal compressor affected facilities, you must establish a limit on temperature in accordance with §60.5417a(f) and continuously monitor the temperature as required by §60.5417a(d).

(c) *Control device design analysis to meet the requirements of §60.5412a(a)(2) or (d)(2).* (1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity and temperature and must establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream and the design average temperatures of the coolant fluid at the condenser inlet and outlet.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity and temperature and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete

carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time and design service life of the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity and temperature and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon used for the carbon bed and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems shall incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the Administrator do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the requirements of paragraph (b) of this section to resolve the disagreement. The Administrator may choose to have an authorized representative observe the performance test.

(d) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph (d) applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer must demonstrate that a specific model of control device achieves the performance requirements in paragraph (d)(11) of this section by conducting a performance test as specified in paragraphs (d)(2) through (10) of this section. You must submit a test report for each combustion control device in accordance with the requirements in paragraph (d)(12) of this section.

(2) Performance testing must consist of three 1-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. Propene (propylene) gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90-100 percent of maximum design rate (fixed rate).

(ii) 70-100-70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30-70-30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0-30-0 percent (ramp up, ramp down). Begin the test at the minimum firing rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10-15 minute time range, incrementally ramp back down to the minimum firing rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures must be tested simultaneously and with all burners operational. Results must be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System. A graphic presentation or strip chart of the control device operating data and emissions test data must be included in the test report in accordance with paragraph (d)(12) of this section. Inlet fuel meter data may be manually recorded provided that all inlet fuel data readings are included in the final report.

(4) Inlet testing must be conducted as specified in paragraphs (d)(4)(i) and (ii) of this section.

(i) The inlet gas flow metering system must be located in accordance with Method 2A of appendix A-1 of this part (or other approved procedure) to measure inlet gas flow rate at the control device inlet location. You must position the fitting for filling fuel sample containers a minimum of eight pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet flow rate must be determined using Method 2A of appendix A-1 of this part. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute test.

(5) Inlet gas sampling must be conducted as specified in paragraphs (d)(5)(i) and (ii) of this section.

(i) At the inlet gas sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3-hour period. Filling must be conducted as specified in paragraphs (d)(5)(i)(A) through (C) of this section.

(A) Open the canister sampling valve at the beginning of each test run, and close the canister at the end of each test run.

(B) Fill one canister across the three test runs such that one composite fuel sample exists for each test condition.

(C) Label the canisters individually and record sample information on a chain of custody form.

(ii) Analyze each inlet gas sample using the methods in paragraphs (d)(5)(ii)(A) through (C) of this section. You must include the results in the test report required by paragraph (d)(12) of this section.

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945-03 (incorporated by reference as specified in §60.17).

(B) Hydrogen (H₂), carbon monoxide (CO), carbon dioxide (CO₂), nitrogen (N₂), oxygen (O₂) using ASTM D1945-03 (incorporated by reference as specified in §60.17).

(C) Higher heating value using ASTM D3588-98 or ASTM D4891-89 (incorporated by reference as specified in §60.17).

(6) Outlet testing must be conducted in accordance with the criteria in paragraphs (d)(6)(i) through (v) of this section.

(i) Sample and flow rate must be measured in accordance with paragraphs (d)(6)(i)(A) and (B) of this section.

(A) The outlet sampling location must be a minimum of four equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports must be used.

(B) Flow rate must be measured using Method 1 of appendix A-1 of this part for determining flow measurement traverse point location, and Method 2 of appendix A-1 of this part for measuring duct velocity. If low flow conditions are encountered (*i.e.*, velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer must be used to obtain an accurate flow profile.

(ii) Molecular weight and excess air must be determined as specified in paragraph (d)(7) of this section.

(iii) Carbon monoxide must be determined as specified in paragraph (d)(8) of this section.

(iv) THC must be determined as specified in paragraph (d)(9) of this section.

(v) Visible emissions must be determined as specified in paragraph (d)(10) of this section.

(7) Molecular weight and excess air determination must be performed as specified in paragraphs (d)(7)(i) through (iii) of this section.

(i) An integrated bag sample must be collected during the moisture test required by Method 4 of appendix A-3 of this part following the procedure specified in (d)(7)(i)(A) and (B) of this section. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC-TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(C) and (D) of this section.

(A) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(B) Purge the sampling line with stack gas before opening the valve and beginning to fill the bag. Clearly label each bag and record sample information on a chain of custody form.

(C) The bag contents must be vigorously mixed prior to the gas chromatograph analysis.

(D) The GC-TCD calibration procedure in Method 3C of appendix A-2 of this part must be modified by using EPA Alt-045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, repeat the initial calibration using at least three concentration levels.

(ii) Calculate and report the molecular weight of oxygen, carbon dioxide, methane and nitrogen in the integrated bag sample and include in the test report specified in paragraph (d)(12) of this section. Moisture must be determined using Method 4 of appendix A-3 of this part. Traverse both ports with the sampling train required by Method 4 of appendix A-3 of this part during each test run. Ambient air must not be introduced into the integrated bag sample required by Method 3C of appendix A-2 of this part during the port change.

(iii) Excess air must be determined using resultant data from the EPA Method 3C tests and EPA Method 3B of appendix A-2 of this part, equation 3B-1, or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17).

(8) Carbon monoxide must be determined using Method 10 of appendix A-4 of this part. Run the test simultaneously with Method 25A of appendix A-7 of this part using the same sampling points. An instrument range of 0-10 parts per million by volume-dry (ppmvd) is recommended.

(9) Total hydrocarbon determination must be performed as specified by in paragraphs (d)(9)(i) through (vii) of this section.

(i) Conduct THC sampling using Method 25A of appendix A-7 of this part, except that the option for locating the probe in the center 10 percent of the stack is not allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during each test run.

(ii) A valid test must consist of three Method 25A tests, each no less than 60 minutes in duration.

(iii) A 0-10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0-30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases must be propane in air and be certified through EPA Protocol 1—"EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," (incorporated by reference as specified in §60.17).

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent CO₂, as measured by Method 3C of appendix A-2 of this part. You must use the following equation for this diluent concentration correction:

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Where:

C_{meas} = The measured concentration of the pollutant.

$\text{CO}_{2\text{meas}}$ = The measured concentration of the CO_2 diluent.

3 = The corrected reference concentration of CO_2 diluent.

C_{corr} = The corrected concentration of the pollutant.

(vii) Subtraction of methane or ethane from the THC data is not allowed in determining results.

(10) Visible emissions must be determined using Method 22 of appendix A-7 of this part. The test must be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, must be taken once per test run and the 12 photos included in the test report specified in paragraph (d)(12) of this section.

(11) *Performance test criteria.* (i) The control device model tested must meet the criteria in paragraphs (d)(11)(i)(A) through (D) of this section. These criteria must be reported in the test report required by paragraph (d)(12) of this section.

(A) Results from Method 22 of appendix A-7 of this part determined under paragraph (d)(10) of this section with no indication of visible emissions.

(B) Average results from Method 25A of appendix A-7 of this part determined under paragraph (d)(9) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2 .

(C) Average CO emissions determined under paragraph (d)(8) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2 .

(D) Excess air determined under paragraph (d)(7) of this section equal to or greater than 150 percent.

(ii) The manufacturer must determine a maximum inlet gas flow rate which must not be exceeded for each control device model to achieve the criteria in paragraph (d)(11)(iii) of this section. The maximum inlet gas flow rate must be included in the test report required by paragraph (d)(12) of this section.

(iii) A manufacturer must demonstrate a destruction efficiency of at least 95 percent for THC, as propane. A control device model that demonstrates a destruction efficiency of 95 percent for

THC, as propane, will meet the control requirement for 95 percent destruction of VOC and methane (if applicable) required under this subpart.

(12) The owner or operator of a combustion control device model tested under this paragraph must submit the information listed in paragraphs (d)(12)(i) through (vi) of this section in the test report required by this section in accordance with §60.5420a(b)(10). Owners or operators who claim that any of the performance test information being submitted is confidential business information (CBI) must submit a complete file including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to Attn: CBI Document Control Officer; Office of Air Quality Planning and Standards (OAQPS) CBIO Room 521; 109 T.W. Alexander Drive; RTP, NC 27711. The same file with the CBI omitted must be submitted to *Oil ___ and ___ Gas ___ PT@EPA.GOV*.

(i) A full schematic of the control device and dimensions of the device components.

(ii) The maximum net heating value of the device.

(iii) The test fuel gas flow range (in both mass and volume). Include the maximum allowable inlet gas flow rate.

(iv) The air/stream injection/assist ranges, if used.

(v) The test conditions listed in paragraphs (d)(12)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess air range.

(G) Flame arrestor(s).

(H) Burner manifold.

(I) Pilot flame indicator.

(J) Pilot flame design fuel and calculated or measured fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, strip charts, or other graphic presentations of the data annotated with test times and calibration values.

(e) *Continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section.* This paragraph (e) applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (d) of this section. Owners or operators must demonstrate that a control device achieves the performance criteria in paragraph (d)(11) of this section by installing a device tested under paragraph (d) of this section, complying with the criteria specified in paragraphs (e)(1) through (8) of this section, maintaining the records specified in §60.5420a(c)(2) or (c)(5)(vi) and submitting the report specified in §60.5420a(b)(10).

(1) The inlet gas flow rate must be equal to or less than the maximum specified by the manufacturer.

(2) A pilot flame must be present at all times of operation.

(3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22 of appendix A-7 of this part must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(4) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(5) Following return to operation from maintenance or repair activity, each device must pass a visual observation according to EPA Method 22 of appendix A-7 of this part as described in paragraph (e)(3) of this section.

(6) If the owner or operator operates a combustion control device model tested under this section, an electronic copy of the performance test results required by this section shall be submitted via

email to *Oil ____ and ____ Gas ____ PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/*.

(7) Ensure that each enclosed combustion control device is maintained in a leak free condition.

(8) Operate each control device following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

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§60.5415a How do I demonstrate continuous compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, and collection of fugitive emissions components at a compressor station affected facilities, and affected facilities at onshore natural gas processing plants?

(a) For each well affected facility, you must demonstrate continuous compliance by submitting the reports required by §60.5420a(b)(1) and (2) and maintaining the records for each completion operation specified in §60.5420a(c)(1).

(b) For each centrifugal compressor affected facility and each pneumatic pump affected facility, you must demonstrate continuous compliance according to paragraph (b)(3) of this section except as provided in paragraph (b)(4) of this section. For each centrifugal compressor affected facility, you also must demonstrate continuous compliance according to paragraphs (b)(1) and (2) of this section.

(1) You must reduce methane and VOC emissions from the wet seal fluid degassing system by 95.0 percent or greater.

(2) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of §60.5412a(a) using the procedures specified in paragraphs (b)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in §60.5412a(a)(2), you may demonstrate compliance according to paragraph (b)(2)(viii) of this section. You may switch between compliance with paragraphs (b)(2)(i) through (vii) of this section and compliance with paragraph (b)(2)(viii) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next annual report, following the change.

(i) You must operate below (or above) the site specific maximum (or minimum) parameter value established according to the requirements of §60.5417a(f)(1).

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with §60.5417a(e) except that the inlet gas flow rate to the control device must not be averaged.

(iii) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (b)(2)(ii) of this section is either equal to or greater than the minimum monitoring value or equal to or less than the maximum monitoring value established under paragraph (b)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in §60.5413a(d), compliance with the operating parameter limit is achieved when the criteria in §60.5413a(e) are met.

(iv) You must operate the continuous monitoring system required in §60.5417a(a) at all times the affected source is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments). A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(v) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other required data collection periods to assess the operation of the control device and associated control system.

(vi) Failure to collect required data is a deviation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments).

(vii) If you use a combustion control device to meet the requirements of §60.5412a(a)(1) and you demonstrate compliance using the test procedures specified in §60.5413a(b), or you use a flare designed and operated in accordance with §60.18(b), you must comply with paragraphs (b)(2)(vii)(A) through (D) of this section.

(A) A pilot flame must be present at all times of operation.

(B) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section

11 of EPA Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(C) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(D) Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A-7 of this part visual observation as described in paragraph (b)(2)(vii)(B) of this section.

(viii) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in §60.5412a(a)(2), you must demonstrate compliance using the procedures in paragraphs (b)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to §60.5417a(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with §60.5417a(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (b)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (b)(2)(viii)(A) of this section.

(D) Except as provided in paragraphs (b)(2)(viii)(D)(1) and (2) of this section, at the end of each operating day, you must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (b)(2)(viii)(C) of this section.

(1) After the compliance dates specified in §60.5370a(a), if you have less than 120 days of data for determining average TOC emission reduction, you must calculate the average TOC emission reduction for the first 120 days of operation after the compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the 120-day average TOC emission reduction is equal to or greater than 95.0 percent.

(2) After 120 days and no more than 364 days of operation after the compliance date specified in §60.5370a(a), you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days between the current day and the applicable compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the average TOC emission reduction is equal to or greater than 95.0 percent.

(E) If you have data for 365 days or more of operation, you have demonstrated compliance with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in paragraph (b)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

(3) You must submit the annual reports required by 60.5420a(b)(1) and (3) and maintain the records as specified in §60.5420a(c)(2), (6) through (11), and (17), as applicable.

(4) Pneumatic pump affected facilities at a well site are not subject to the requirements of paragraphs (b)(3) of this section from June 2, 2017, until August 31, 2017.

(c) For each reciprocating compressor affected facility complying with §60.5385a(a)(1) or (2), you must demonstrate continuous compliance according to paragraphs (c)(1) through (3) of this section. For each reciprocating compressor affected facility complying with §60.5385a(a)(3), you must demonstrate continuous compliance according to paragraph (c)(4) of this section.

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor affected facility or track the number of months since initial startup or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) You must submit the annual reports as required in §60.5420a(b)(1) and (4) and maintain records as required in §60.5420a(c)(3).

(3) You must replace the reciprocating compressor rod packing on or before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

(4) You must operate the rod packing emissions collection system under negative pressure and continuously comply with the cover and closed vent requirements in §60.5416a(a) and (b).

(d) For each pneumatic controller affected facility, you must demonstrate continuous compliance according to paragraphs (d)(1) through (3) of this section.

(1) You must continuously operate the pneumatic controllers as required in §60.5390a(a), (b), or (c).

(2) You must submit the annual reports as required in §60.5420a(b)(1) and (5).

(3) You must maintain records as required in §60.5420a(c)(4).

(e) You must demonstrate continuous compliance according to paragraph (e)(3) of this section for each storage vessel affected facility, for which you are using a control device or routing emissions to a process to meet the requirement of §60.5395a(a)(2).

(1)-(2) [Reserved]

(3) For each storage vessel affected facility, you must comply with paragraphs (e)(3)(i) and (ii) of this section.

(i) You must reduce VOC emissions as specified in §60.5395a(a)(2).

(ii) For each control device installed to meet the requirements of §60.5395a(a)(2), you must demonstrate continuous compliance with the performance requirements of §60.5412a(d) for each storage vessel affected facility using the procedure specified in paragraph (e)(3)(ii)(A) and either (e)(3)(ii)(B) or (e)(3)(ii)(C) of this section.

(A) You must comply with §60.5416a(c) for each cover and closed vent system.

(B) You must comply with §60.5417a(h) for each control device.

(C) Each closed vent system that routes emissions to a process must be operated as specified in §60.5411a(c)(2) and (3).

(f) For affected facilities at onshore natural gas processing plants, continuous compliance with methane and VOC requirements is demonstrated if you are in compliance with the requirements of §60.5400a.

(g) For each sweetening unit affected facility at onshore natural gas processing plants, you must demonstrate continuous compliance with the standards for SO₂ specified in §60.5405a(b) according to paragraphs (g)(1) and (2) of this section.

(1) The minimum required SO₂ emission reduction efficiency (Z_c) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology.

(i) If $R \geq Z_c$, your affected facility is in compliance.

(ii) If $R < Z_c$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in §60.5406a(c)(1).

(h) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, you must demonstrate continuous compliance with the fugitive emission standards specified in §60.5397a according to paragraphs (h)(1) through (4) of this section.

(1) You must conduct periodic monitoring surveys as required in §60.5397a(g).

(2) You must repair or replace each identified source of fugitive emissions as required in §60.5397a(h).

(3) You must maintain records as specified in §60.5420a(c)(15).

(4) You must submit annual reports for collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station as required in §60.5420a(b)(1) and (7).

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

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§60.5416a What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my centrifugal compressor, reciprocating compressor, pneumatic pump, and storage vessel affected facilities?

For each closed vent system or cover at your storage vessel, centrifugal compressor, reciprocating compressor and pneumatic pump affected facilities, you must comply with the applicable requirements of paragraphs (a) through (c) of this section, except as provided in paragraph (d) of this section.

(a) Inspections for closed vent systems and covers installed on each centrifugal compressor, reciprocating compressor or pneumatic pump affected facility. Except as provided in paragraphs (b)(11) and (12) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) and (2) of this section, inspect each cover according to the procedures and schedule specified in paragraph (a)(3) of this section, and inspect each bypass device according to the procedures of paragraph (a)(4) of this section.

(1) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (e.g., a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1)(i) and (ii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(ii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (b) of this section to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(2) For closed vent system components other than those specified in paragraph (a)(1) of this section, you must meet the requirements of paragraphs (a)(2)(i) through (iii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(ii) Conduct annual inspections according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the components or connections operate with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(iii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(3) For each cover, you must meet the requirements in paragraphs (a)(3)(i) and (ii) of this section.

(i) Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.*, fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(ii) You must initially conduct the inspections specified in paragraph (a)(3)(i) of this section following the installation of the cover. Thereafter, you must perform the inspection at least once every calendar year, except as provided in paragraphs (b)(11) and (12) of this section. You must maintain records of the inspection results as specified in §60.5420a(c)(7).

(4) For each bypass device, except as provided for in §60.5411a(c)(3)(ii), you must meet the requirements of paragraphs (a)(4)(i) or (ii) of this section.

(i) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere.

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections according to §60.5420a(c)(8).

(b) No detectable emissions test methods and procedures. If you are required to conduct an inspection of a closed vent system or cover at your centrifugal compressor, reciprocating compressor, or pneumatic pump affected facility as specified in paragraphs (a)(1), (2), or (3) of this section, you must meet the requirements of paragraphs (b)(1) through (13) of this section.

(1) You must conduct the no detectable emissions test procedure in accordance with Method 21 of appendix A-7 of this part.

(2) The detection instrument must meet the performance criteria of Method 21 of appendix A-7 of this part, except that the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) You must calibrate the detection instrument before use on each day of its use by the procedures specified in Method 21 of appendix A-7 of this part.

(4) Calibration gases must be as specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in Method 21 of appendix A-7 of this part.

(6) Your detection instrument must meet the performance criteria specified in paragraphs (b)(6)(i) and (ii) of this section.

(i) Except as provided in paragraph (b)(6)(ii) of this section, the detection instrument must meet the performance criteria of Method 21 of appendix A-7 of this part, except the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inerts that are not organic hazardous air pollutants or volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(ii) If no instrument is available that will meet the performance criteria specified in paragraph (b)(6)(i) of this section, you may adjust the instrument readings by multiplying by the average response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (b)(6)(i) of this section.

(7) You must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (b)(7)(i) or (ii) of this section.

(i) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(ii) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (b)(5) of this section with the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (b)(7) of this section is less than 500 parts per million by volume.

(9) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (b)(9)(i) and (ii) of this section, except as provided in paragraph (b)(10) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 15 calendar days after the leak is detected.

(10) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(11) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (b)(11)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a)(1), (2), or (3) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(12) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (b)(12)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(13) *Records*. Records shall be maintained as specified in this section and in §60.5420a(c)(9).

(c) *Cover and closed vent system inspections for storage vessel affected facilities*. If you install a control device or route emissions to a process, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (c)(1) of this section, inspect each cover according to the procedures and schedule specified in paragraph (c)(2) of this section, and inspect each bypass device according to the procedures of paragraph (c)(3) of this section. You must also comply with the requirements of (c)(4) through (7) of this section.

(1) For each closed vent system, you must conduct an inspection at least once every calendar month as specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(2) For each cover, you must conduct inspections at least once every calendar month as specified in paragraphs (c)(2)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in §60.5420a(c)(7).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (e.g., fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(3) For each bypass device, except as provided for in §60.5411a(c)(3)(ii), you must meet the requirements of paragraphs (c)(3)(i) or (ii) of this section.

(i) You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere.

Set the flow indicator to trigger an audible alarm, or initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is sounded according to §60.5420a(c)(8).

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections and records of each time the key is checked out, if applicable, according to §60.5420a(c)(8).

(4) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (c)(4)(i) through (iii) of this section, except as provided in paragraph (c)(5) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 30 calendar days after the leak is detected.

(iii) Grease or another applicable substance must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

(5) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(6) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (c)(6)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (c)(1) or (2) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(7) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (c)(7)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

- (i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.
- (ii) You have a written plan that requires inspection of the equipment at least once every 5 years.
- (d) Pneumatic pump affected facilities at a well site are not subject to the requirements of paragraphs (a) and (b) of this section from June 2, 2017, until August 31, 2017.

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

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§60.5417a What are the continuous control device monitoring requirements for my centrifugal compressor and storage vessel affected facilities?

You must meet the applicable requirements of this section to demonstrate continuous compliance for each control device used to meet emission standards for your storage vessel or centrifugal compressor affected facility.

(a) For each control device used to comply with the emission reduction standard for centrifugal compressor affected facilities in §60.5380a(a)(1), you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with §60.5412a(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section. If you install and operate an enclosed combustion device which is not specifically listed in paragraph (d) of this section, you must demonstrate continuous compliance according to paragraphs (h)(1) through (h)(4) of this section.

(b) You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) If you are required to install a continuous parameter monitoring system, you must meet the specifications and requirements in paragraphs (c)(1) through (4) of this section.

(1) Each continuous parameter monitoring system must measure data values at least once every hour and record the parameters in paragraphs (c)(1)(i) or (ii) of this section.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(2) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your approved site-specific monitoring plan. Heat sensing monitoring devices that indicate the continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements in this section.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §60.13(b).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §60.7(c), (d), and (f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in accordance with the site-specific monitoring plan. Heat sensing monitoring devices that indicate the continuous ignition a pilot flame are exempt from the calibration, quality assurance and quality control requirements in this section.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in paragraph (d)(1), (2), or (3) of this section.

(1) A continuous monitoring system that measures the operating parameters in paragraphs (d)(1)(i) through (viii) of this section, as applicable.

(i) For a thermal vapor incinerator that demonstrates during the performance test conducted under §60.5413a(b) that combustion zone temperature is an accurate indicator of performance, a

temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{Celsius}$, or ± 2.5 $^{\circ}\text{Celsius}$, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(ii) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{Celsius}$, or ± 2.5 $^{\circ}\text{Celsius}$, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame. The heat sensing monitoring device is exempt from the calibration requirements of this section.

(iv) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{Celsius}$, or ± 2.5 $^{\circ}\text{Celsius}$, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(v) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{Celsius}$, or ± 2.5 $^{\circ}\text{Celsius}$, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(vi) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(1)(vi)(A) and (B) of this section.

(A) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(B) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ± 1 percent of the temperature being monitored in $^{\circ}\text{Celsius}$, or ± 2.5 $^{\circ}\text{Celsius}$, whichever value is greater.

(vii) For a nonregenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a design analysis performed as specified in §60.5413a(c)(3). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(viii) For a combustion control device whose model is tested under §60.5413a(d), a continuous monitoring system meeting the requirements of paragraphs (d)(1)(viii)(A) and (B) of this section. If you comply with the periodic testing requirements of §60.5413a(b)(5)(ii), you are not required to continuously monitor the gas flow rate under paragraph (d)(1)(viii)(A) of this section.

(A) The continuous monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ± 2 percent or better at the maximum expected flow rate. The flow rate at the inlet to the combustion device must not exceed the maximum flow rate determined by the manufacturer.

(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the control device.

(2) An organic monitoring device equipped with a continuous recorder that measures the concentration level of organic compounds in the exhaust vent stream from the control device. The monitor must meet the requirements of Performance Specification 8 or 9 of appendix B of this part. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications.

(3) A continuous monitoring system that measures operating parameters other than those specified in paragraph (d)(1) or (2) of this section, upon approval of the Administrator as specified in §60.13(i).

(e) You must calculate the daily average value for each monitored operating parameter for each operating day, using the data recorded by the monitoring system, except for inlet gas flow rate and data from the heat sensing devices that indicate the presence of a pilot flame. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of §60.5412a(a)(1) or (2). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) If you conduct performance tests in accordance with the requirements of §60.5413a(b) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412a(a)(1) or (2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(ii) If you use a condenser design analysis in accordance with the requirements of §60.5413a(c) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412a(a)(2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on the condenser design analysis and supplemented, as necessary, by the condenser manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under §60.5413a(d) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412a(a)(1), then your control device inlet gas flow rate must not exceed the maximum inlet gas flow rate determined by the manufacturer.

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of §60.5413a(b) to demonstrate that the condenser achieves the applicable performance requirements in §60.5412a(a)(2), then the condenser performance curve must be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(ii) If you use a control device design analysis in accordance with the requirements of §60.5413a(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in §60.5412a(a)(2), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (6) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (6) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section or when the heat sensing device indicates that there is no pilot flame present.

(2) If you are subject to §60.5412a(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in §60.5415a(b)(2)(viii)(D) is less than 95.0 percent.

(3) If you are subject to §60.5412a(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in §60.5415a(b)(2)(viii)(D)(1) or (2) is less than 95.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraph (g)(5)(i) or (ii) of this section are met.

(i) For each bypass line subject to §60.5411a(a)(3)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to §60.5411a(a)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under §60.5413a(d), a deviation occurs when the conditions of paragraphs (g)(6)(i) or (ii) of this section are met.

(i) The inlet gas flow rate exceeds the maximum established during the test conducted under §60.5413a(d).

(ii) Failure of the monthly visible emissions test conducted under §60.5413a(e)(3) occurs.

(h) For each control device used to comply with the emission reduction standard in §60.5395a(a)(2) for your storage vessel affected facility, you must demonstrate continuous compliance according to paragraphs (h)(1) through (h)(4) of this section. You are exempt from the requirements of this paragraph if you install a control device model tested in accordance with §60.5413a(d)(2) through (10), which meets the criteria in §60.5413a(d)(11), the reporting requirement in §60.5413a(d)(12), and meet the continuous compliance requirement in §60.5413a(e).

(1) For each combustion device you must conduct inspections at least once every calendar month according to paragraphs (h)(1)(i) through (iv) of this section. Monthly inspections must be separated by at least 14 calendar days.

(i) Conduct visual inspections to confirm that the pilot is lit when vapors are being routed to the combustion device and that the continuous burning pilot flame is operating properly.

(ii) Conduct inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22 of appendix A of this part. The observation period shall be 15 minutes. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period.

(iii) Conduct olfactory, visual and auditory inspections of all equipment associated with the combustion device to ensure system integrity.

(iv) For any absence of the pilot flame, or other indication of smoking or improper equipment operation (*e.g.*, visual, audible, or olfactory), you must ensure the equipment is returned to proper operation as soon as practicable after the event occurs. At a minimum, you must perform the procedures specified in paragraphs (h)(1)(iv)(A) and (B) of this section.

(A) You must check the air vent for obstruction. If an obstruction is observed, you must clear the obstruction as soon as practicable.

(B) You must check for liquid reaching the combustor.

(2) For each vapor recovery device, you must conduct inspections at least once every calendar month to ensure physical integrity of the control device according to the manufacturer's instructions. Monthly inspections must be separated by at least 14 calendar days.

(3) Each control device must be operated following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions. Records of the manufacturer's written operating instructions, procedures, and maintenance schedule must be available for inspection as specified in §60.5420a(c)(13).

(4) Conduct a periodic performance test no later than 60 months after the initial performance test as specified in §60.5413a(b)(5)(ii) and conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test.

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§60.5420a What are my notification, reporting, and recordkeeping requirements?

(a) You must submit the notifications according to paragraphs (a)(1) and (2) of this section if you own or operate one or more of the affected facilities specified in §60.5365a that was constructed, modified or reconstructed during the reporting period.

(1) If you own or operate an affected facility that is the group of all equipment within a process unit at an onshore natural gas processing plant, or a sweetening unit at an onshore natural gas processing plant, you must submit the notifications required in §60.7(a)(1), (3), and (4). If you

own or operate a well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, or collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station, you are not required to submit the notifications required in §60.7(a)(1), (3), and (4).

(2)(i) If you own or operate a well affected facility, you must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the United States Well Number; the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format.

(ii) If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you are considered to have met the advance notification requirements of paragraph (a)(2)(i) of this section.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (8) and (12) of this section and performance test reports as specified in paragraph (b)(9) or (10) of this section, if applicable, except as provided in paragraph (b)(13) of this section. You must submit annual reports following the procedure specified in paragraph (b)(11) of this section. The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to §60.5410a. Subsequent annual reports are due no later than same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (8) of this section, except as provided in paragraph (b)(13) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

(1) The general information specified in paragraphs (b)(1)(i) through (iv) of this section for all reports.

(i) The company name, facility site name associated with the affected facility, US Well ID or US Well ID associated with the affected facility, if applicable, and address of the affected facility. If an address is not available for the site, include a description of the site location and provide the latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(2) For each well affected facility, the information in paragraphs (b)(2)(i) through (iii) of this section.

(i) Records of each well completion operation as specified in paragraphs (c)(1)(i) through (iv) and (vi) of this section, if applicable, for each well affected facility conducted during the reporting period. In lieu of submitting the records specified in paragraph (c)(1)(i) through (iv) of this section, the owner or operator may submit a list of the well completions with hydraulic fracturing completed during the reporting period and the records required by paragraph (c)(1)(v) of this section for each well completion.

(ii) Records of deviations specified in paragraph (c)(1)(ii) of this section that occurred during the reporting period.

(iii) Records specified in paragraph (c)(1)(vii) of this section, if applicable, that support a determination under 60.5432a that the well affected facility is a low pressure well as defined in 60.5430a.

(3) For each centrifugal compressor affected facility, the information specified in paragraphs (b)(3)(i) through (iv) of this section.

(i) An identification of each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period.

(ii) Records of deviations specified in paragraph (c)(2) of this section that occurred during the reporting period.

(iii) If required to comply with §60.5380a(a)(2), the records specified in paragraphs (c)(6) through (11) of this section.

(iv) If complying with §60.5380a(a)(1) with a control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e), records specified in paragraph (c)(2)(i) through (c)(2)(vii) of this section for each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period.

(4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) The cumulative number of hours of operation or the number of months since initial startup or since the previous reciprocating compressor rod packing replacement, whichever is later. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) Records of deviations specified in paragraph (c)(3)(iii) of this section that occurred during the reporting period.

(5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (iii) of this section.

(i) An identification of each pneumatic controller constructed, modified or reconstructed during the reporting period, including the identification information specified in §60.5390a(b)(2) or (c)(2).

(ii) If applicable, documentation that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than 6 standard cubic feet per hour are required and the reasons why.

(iii) Records of deviations specified in paragraph (c)(4)(v) of this section that occurred during the reporting period.

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) through (vii) of this section.

(i) An identification, including the location, of each storage vessel affected facility for which construction, modification or reconstruction commenced during the reporting period. The location of the storage vessel shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) Documentation of the VOC emission rate determination according to §60.5365a(e) for each storage vessel that became an affected facility during the reporting period or is returned to service during the reporting period.

(iii) Records of deviations specified in paragraph (c)(5)(iii) of this section that occurred during the reporting period.

(iv) A statement that you have met the requirements specified in §60.5410a(h)(2) and (3).

(v) You must identify each storage vessel affected facility that is removed from service during the reporting period as specified in §60.5395a(c)(1)(ii), including the date the storage vessel affected facility was removed from service.

(vi) You must identify each storage vessel affected facility returned to service during the reporting period as specified in §60.5395a(c)(3), including the date the storage vessel affected facility was returned to service.

(vii) If complying with §60.5395a(a)(2) with a control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e), records specified in paragraphs

(c)(5)(vi)(A) through (F) of this section for each storage vessel constructed, modified, reconstructed or returned to service during the reporting period.

(7) For the collection of fugitive emissions components at each well site and the collection of fugitive emissions components at each compressor station within the company-defined area, the records of each monitoring survey including the information specified in paragraphs (b)(7)(i) through (xii) of this section. For the collection of fugitive emissions components at a compressor station, if a monitoring survey is waived under §60.5397a(g)(5), you must include in your annual report the fact that a monitoring survey was waived and the calendar months that make up the quarterly monitoring period for which the monitoring survey was waived.

(i) Date of the survey.

(ii) Beginning and end time of the survey.

(iii) Name of operator(s) performing survey. If the survey is performed by optical gas imaging, you must note the training and experience of the operator.

(iv) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(v) Monitoring instrument used.

(vi) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(vii) Number and type of components for which fugitive emissions were detected.

(viii) Number and type of fugitive emissions components that were not repaired as required in §60.5397a(h).

(ix) Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.

(x) The date of successful repair of the fugitive emissions component.

(xi) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.

(xii) Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

(8) For each pneumatic pump affected facility, the information specified in paragraphs (b)(8)(i) through (iii) of this section.

(i) For each pneumatic pump that is constructed, modified or reconstructed during the reporting period, you must provide certification that the pneumatic pump meets one of the conditions described in paragraphs (b)(8)(i)(A), (B) or (C) of this section.

(A) No control device or process is available on site.

(B) A control device or process is available on site and the owner or operator has determined in accordance with §60.5393a(b)(5) that it is technically infeasible to capture and route the emissions to the control device or process.

(C) Emissions from the pneumatic pump are routed to a control device or process. If the control device is designed to achieve less than 95 percent emissions reduction, specify the percent emissions reductions the control device is designed to achieve.

(ii) For any pneumatic pump affected facility which has been previously reported as required under paragraph (b)(8)(i) of this section and for which a change in the reported condition has occurred during the reporting period, provide the identification of the pneumatic pump affected facility and the date it was previously reported and a certification that the pneumatic pump meets one of the conditions described in paragraphs (b)(8)(ii)(A), (B) or (C) or (D) of this section.

(A) A control device has been added to the location and the pneumatic pump now reports according to paragraph (b)(8)(i)(C) of this section.

(B) A control device has been added to the location and the pneumatic pump affected facility now reports according to paragraph (b)(8)(i)(B) of this section.

(C) A control device or process has been removed from the location or otherwise is no longer available and the pneumatic pump affected facility now report according to paragraph (b)(8)(i)(A) of this section.

(D) A control device or process has been removed from the location or is otherwise no longer available and the owner or operator has determined in accordance with §60.5393a(b)(5) through an engineering evaluation that it is technically infeasible to capture and route the emissions to another control device or process.

(iii) Records of deviations specified in paragraph (c)(16)(ii) of this section that occurred during the reporting period.

(9) Within 60 days after the date of completing each performance test (see §60.8) required by this subpart, except testing conducted by the manufacturer as specified in §60.5413a(d), you must submit the results of the performance test following the procedure specified in either paragraph (b)(9)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (https://www3.epa.gov/ttn/chief/ert/ert_info.html) at the time of the test, you must submit the results of the performance test to the EPA via the

Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (<https://cdx.epa.gov/>.) Performance test data must be submitted in a file format generated through the use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in §60.4.

(10) For combustion control devices tested by the manufacturer in accordance with §60.5413a(d), an electronic copy of the performance test results required by §60.5413a(d) shall be submitted via email to *Oil ___ and ___ Gas ___ PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: epa.gov/airquality/oilandgas/.

(11) You must submit reports to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX (<https://cdx.epa.gov/>.) You must use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (<https://www3.epa.gov/ttn/chief/cedri/>). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The reports must be submitted by the deadlines specified in this subpart, regardless of the method in which the reports are submitted.

(12) You must submit the certification signed by the qualified professional engineer according to §60.5411a(d) for each closed vent system routing to a control device or process.

(13) The collection of fugitive emissions components at a well site (as defined in §60.5430a), the collection of fugitive emissions components at a compressor station (as defined in §60.5430a), and pneumatic pump affected facilities at a well site (as defined in §60.5365a(h)(2)) are not subject to the requirements of paragraph (b)(1) of this section from June 2, 2017, until August 31, 2017.

(c) *Recordkeeping requirements.* You must maintain the records identified as specified in §60.7(f) and in paragraphs (c)(1) through (16) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years. Any

records required to be maintained by this subpart that are submitted electronically via the EPA's CDX may be maintained in electronic format.

(1) The records for each well affected facility as specified in paragraphs (c)(1)(i) through (vii) of this section, as applicable. For each well affected facility for which you make a claim that the well affected facility is not subject to the requirements for well completions pursuant to 60.5375a(g), you must maintain the record in paragraph (c)(1)(vi), only.

(i) Records identifying each well completion operation for each well affected facility;

(ii) Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in §60.5375a.

(iii) Records required in §60.5375a(b) or (f)(3) for each well completion operation conducted for each well affected facility that occurred during the reporting period. You must maintain the records specified in paragraphs (c)(1)(iii)(A) through (C) of this section.

(A) For each well affected facility required to comply with the requirements of §60.5375a(a), you must record: The location of the well; the United States Well Number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time of each attempt to direct flowback to a separator as required in §60.5375a(a)(1)(ii); the date and time of each occurrence of returning to the initial flowback stage under §60.5375a(a)(1)(i); and the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery and disposition of recovery (*i.e.*, routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve); duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours. In addition, for wells where it is technically infeasible to route the recovered gas to any of the four options specified in §60.5375a(a)(1)(ii), you must record the reasons for the claim of technical infeasibility with respect to all four options provided in that subparagraph, including but not limited to; name and location of the nearest gathering line and technical considerations preventing routing to this line; capture, reinjection, and reuse technologies considered and aspects of gas or equipment preventing use of recovered gas as a fuel onsite; and technical considerations preventing use of recovered gas for other useful purpose that that a purchased fuel or raw material would serve.

(B) For each well affected facility required to comply with the requirements of §60.5375a(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the flow line.

(C) For each well affected facility for which you make a claim that it meets the criteria of §60.5375a(a)(1)(iii)(A), you must maintain the following:

(I) Records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record: The date and time of each attempt to direct flowback to a separator; the date and time of

each occurrence of returning to the initial flowback stage; duration of recovery and disposition of recovery (*i.e.* routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve).

(2) If applicable, records that the conditions of §60.5375a(1)(iii)(A) are no longer met and that the well completion operation has been stopped and a separator installed. The records shall include the date and time the well completion operation was stopped and the date and time the separator was installed.

(3) A record of the claim signed by the certifying official that no liquids collection is at the well site. The claim must include a certification by a certifying official of truth, accuracy and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(iv) For each well affected facility for which you claim an exception under §60.5375a(a)(3), you must record: The location of the well; the United States Well Number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.

(v) For each well affected facility required to comply with both §60.5375a(a)(1) and (3), if you are using a digital photograph in lieu of the records required in paragraphs (c)(1)(i) through (iv) of this section, you must retain the records of the digital photograph as specified in §60.5410a(a)(4).

(vi) For each well affected facility for which you make a claim that the well affected facility is not subject to the well completion standards according to 60.5375a(g), you must maintain:

(A) A record of the analysis that was performed in order to make that claim, including but not limited to, GOR values for established leases and data from wells in the same basin and field;

(B) The location of the well; the United States Well Number;

(C) A record of the claim signed by the certifying official. The claim must include a certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(vii) For each well affected facility for which you determine according to §60.5432a that it is a low pressure well, a record of the determination and supporting inputs and calculations.

(2) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in §60.5380a. Except as specified in paragraph (c)(2)(vii) of this section, you must maintain the records in paragraphs (c)(2)(i) through (vi) of this section for each control device

tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e) and used to comply with §60.5380a(a)(1) for each centrifugal compressor.

(i) Make, model and serial number of purchased device.

(ii) Date of purchase.

(iii) Copy of purchase order.

(iv) Location of the centrifugal compressor and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(v) Inlet gas flow rate.

(vi) Records of continuous compliance requirements in §60.5413a(e) as specified in paragraphs (c)(2)(vi)(A) through (E) of this section.

(A) Records that the pilot flame is present at all times of operation.

(B) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15 minute period.

(C) Records of the maintenance and repair log.

(D) Records of the visible emissions test following return to operation from a maintenance or repair activity.

(E) Records of the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(vii) As an alternative to the requirements of paragraph (c)(2)(iv) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the centrifugal compressor and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the centrifugal compressor and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(3) For each reciprocating compressor affected facility, you must maintain the records in paragraphs (c)(3)(i) through (iii) of this section.

(i) Records of the cumulative number of hours of operation or number of months since initial startup or the previous replacement of the reciprocating compressor rod packing, whichever is

later. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system as specified in §60.5385a(a)(3).

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in §60.5385a.

(4) For each pneumatic controller affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (v) of this section, as applicable.

(i) Records of the date, location and manufacturer specifications for each pneumatic controller constructed, modified or reconstructed.

(ii) Records of the demonstration that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required and the reasons why.

(iii) If the pneumatic controller is not located at a natural gas processing plant, records of the manufacturer's specifications indicating that the controller is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour.

(iv) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(v) Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in §60.5390a.

(5) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) through (vi) of this section.

(i) If required to reduce emissions by complying with §60.5395a(a)(2), the records specified in §§60.5420a(c)(6) through (8), 60.5416a(c)(6)(ii), and 60.5416a(c)(7)(ii). You must maintain the records in paragraph (c)(5)(vi) of this part for each control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e) and used to comply with §60.5395a(a)(2) for each storage vessel.

(ii) Records of each VOC emissions determination for each storage vessel affected facility made under §60.5365a(e) including identification of the model or calculation methodology used to calculate the VOC emission rate.

(iii) Records of deviations in cases where the storage vessel was not operated in compliance with the requirements specified in §§60.5395a, 60.5411a, 60.5412a, and 60.5413a, as applicable.

(iv) For storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), records indicating the number of consecutive days that the vessel is located at a site in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment. If a storage vessel is removed from a site and, within 30 days, is either returned to the site or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the original storage vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

(v) You must maintain records of the identification and location of each storage vessel affected facility.

(vi) Except as specified in paragraph (c)(5)(vi)(G) of this section, you must maintain the records specified in paragraphs (c)(5)(vi)(A) through (F) of this section for each control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e) and used to comply with §60.5395a(a)(2) for each storage vessel.

(A) Make, model and serial number of purchased device.

(B) Date of purchase.

(C) Copy of purchase order.

(D) Location of the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(E) Inlet gas flow rate.

(F) Records of continuous compliance requirements in §60.5413a(e) as specified in paragraphs (c)(5)(vi)(F)(1) through (5) of this section.

(1) Records that the pilot flame is present at all times of operation.

(2) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15 minute period.

(3) Records of the maintenance and repair log.

(4) Records of the visible emissions test following return to operation from a maintenance or repair activity.

(5) Records of the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

(G) As an alternative to the requirements of paragraph (c)(5)(vi)(D) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the storage vessel and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the storage vessel and control device with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(6) Records of each closed vent system inspection required under §60.5416a(a)(1) and (2) for centrifugal compressors, reciprocating compressors and pneumatic pumps, or §60.5416a(c)(1) for storage vessels.

(7) A record of each cover inspection required under §60.5416a(a)(3) for centrifugal or reciprocating compressors or §60.5416a(c)(2) for storage vessels.

(8) If you are subject to the bypass requirements of §60.5416a(a)(4) for centrifugal compressors, reciprocating compressors or pneumatic pumps, or §60.5416a(c)(3) for storage vessels, a record of each inspection or a record of each time the key is checked out or a record of each time the alarm is sounded.

(9) If you are subject to the closed vent system no detectable emissions requirements of §60.5416a(b) for centrifugal compressors, reciprocating compressors or pneumatic pumps, a record of the monitoring conducted in accordance with §60.5416a(b).

(10) For each centrifugal compressor or pneumatic pump affected facility, records of the schedule for carbon replacement (as determined by the design analysis requirements of §60.5413a(c)(2) or (3)) and records of each carbon replacement as specified in §60.5412a(c)(1).

(11) For each centrifugal compressor affected facility subject to the control device requirements of §60.5412a(a), (b), and (c), records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

(12) For each carbon adsorber installed on storage vessel affected facilities, records of the schedule for carbon replacement (as determined by the design analysis requirements of §60.5412a(d)(2)) and records of each carbon replacement as specified in §60.5412a(c)(1).

(13) For each storage vessel affected facility subject to the control device requirements of §60.5412a(c) and (d), you must maintain records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in §60.5417a(h)(3). You must maintain records of EPA Method 22 of appendix A-7 of this part, section 11 results, which include: Company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the

above information or use Figure 22-1 in EPA Method 22 of appendix A-7 of this part. Manufacturer's operating instructions, procedures and maintenance schedule must be available for inspection.

(14) A log of records as specified in §60.5412a(d)(1)(iii), for all inspection, repair and maintenance activities for each control device failing the visible emissions test.

(15) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, the records identified in paragraphs (c)(15)(i) through (iii) of this section.

(i) The fugitive emissions monitoring plan as required in §60.5397a(b), (c), and (d).

(ii) The records of each monitoring survey as specified in paragraphs (c)(15)(ii)(A) through (I) of this section.

(A) Date of the survey.

(B) Beginning and end time of the survey.

(C) Name of operator(s) performing survey. You must note the training and experience of the operator.

(D) Monitoring instrument used.

(E) When optical gas imaging is used to perform the survey, one or more digital photographs or videos, captured from the optical gas imaging instrument used for conduct of monitoring, of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital file, the digital photograph or video may consist of an image of the monitoring survey being performed with a separately operating GPS device within the same digital picture or video, provided the latitude and longitude output of the GPS unit can be clearly read in the digital image.

(F) Fugitive emissions component identification when Method 21 is used to perform the monitoring survey.

(G) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(H) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(I) Documentation of each fugitive emission, including the information specified in paragraphs (c)(15)(ii)(I)(1) through (12) of this section.

- (1) Location.
- (2) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.
- (3) Number and type of components for which fugitive emissions were detected.
- (4) Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.
- (5) Instrument reading of each fugitive emissions component that requires repair when Method 21 is used for monitoring.
- (6) Number and type of fugitive emissions components that were not repaired as required in §60.5397a(h).
- (7) Number and type of components that were tagged as a result of not being repaired during the monitoring survey when the fugitive emissions were initially found as required in §60.5397a(h)(3)(ii).
- (8) If a fugitive emissions component is not tagged, a digital photograph or video of each fugitive emissions component that could not be repaired during the monitoring survey when the fugitive emissions were initially found as required in §60.5397a(h)(3)(ii). The digital photograph or video must clearly identify the location of the component that must be repaired. Any digital photograph or video required under this paragraph can also be used to meet the requirements under paragraph (c)(15)(ii)(E) of this section, as long as the photograph or video is taken with the optical gas imaging instrument, includes the date and the latitude and longitude are either imbedded or visible in the picture.
- (9) Repair methods applied in each attempt to repair the fugitive emissions components.
- (10) Number and type of fugitive emission components placed on delay of repair and explanation for each delay of repair.
- (11) The date of successful repair of the fugitive emissions component.
- (12) Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.
- (iii) For the collection of fugitive emissions components at a compressor station, if a monitoring survey is waived under §60.5397a(g)(5), you must maintain records of the average calendar month temperature, including the source of the information, for each calendar month of the quarterly monitoring period for which the monitoring survey was waived.
- (16) For each pneumatic pump affected facility, you must maintain the records identified in paragraphs (c)(16)(i) through (v) of this section.

- (i) Records of the date, location and manufacturer specifications for each pneumatic pump constructed, modified or reconstructed.
 - (ii) Records of deviations in cases where the pneumatic pump was not operated in compliance with the requirements specified in §60.5393a.
 - (iii) Records on the control device used for control of emissions from a pneumatic pump including the installation date, manufacturer's specifications, and if the control device is designed to achieve less than 95 percent emission reduction, a design evaluation or manufacturer's specifications indicating the percentage reduction achieved the control device is designed to achieve.
 - (iv) Records substantiating a claim according to §60.5393a(b)(5) that it is technically infeasible to capture and route emissions from a pneumatic pump to a control device or process; including the qualified professional engineer certification according to §60.5393a(b)(5)(ii) and the records of the engineering assessment of technical infeasibility performed according to §60.5393a(b)(5)(iii).
 - (v) You must retain copies of all certifications, engineering assessments and related records for a period of five years and make them available if directed by the implementing agency.
- (17) For each closed vent system routing to a control device or process, the records of the assessment conducted according to §60.5411a(d):
- (i) A copy of the assessment conducted according to §60.5411a(d)(1);
 - (ii) A copy of the certification according to §60.5411a(d)(1)(i); and
 - (iii) The owner or operator shall retain copies of all certifications, assessments and any related records for a period of five years, and make them available if directed by the delegated authority.

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

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§60.5421a What are my additional recordkeeping requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?

- (a) You must comply with the requirements of paragraph (b) of this section in addition to the requirements of §60.486a.

(b) The following recordkeeping requirements apply to pressure relief devices subject to the requirements of §60.5401a(b)(1).

(1) When each leak is detected as specified in §60.5401a(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(2) When each leak is detected as specified in §60.5401a(b)(2), the information specified in paragraphs (b)(2)(i) through (x) of this section must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) “Above 500 ppm” if the maximum instrument reading measured by the methods specified in §60.5400a(d) after each repair attempt is 500 ppm or greater.

(v) “Repair delayed” and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4a(a). The designation of equipment subject to the provisions of §60.482-4a(a) must be signed by the owner or operator.

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§60.5422a What are my additional reporting requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of §60.487a(a), (b), (c)(2)(i) through (iv), and (c)(2)(vii) through (viii). You must submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (<https://cdx.epa.gov/>.) Use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (<https://www3.epa.gov/ttn/chief/cedri/>). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 days, you must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in §60.487a(b)(1) through (4): Number of pressure relief devices subject to the requirements of §60.5401a(b) except for those pressure relief devices designated for no detectable emissions under the provisions of §60.482-4a(a) and those pressure relief devices complying with §60.482-4a(c).

(c) An owner or operator must include the information specified in paragraphs (c)(1) and (2) of this section in all semiannual reports in addition to the information required in §60.487a(c)(2)(i) through (vi):

(1) Number of pressure relief devices for which leaks were detected as required in §60.5401a(b)(2); and

(2) Number of pressure relief devices for which leaks were not repaired as required in §60.5401a(b)(3).

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§60.5423a What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?

(a) You must retain records of the calculations and measurements required in §§60.5405a(a) and (b) and 60.5407a(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under §60.7(f) of the General Provisions.

(b) You must submit a report of excess emissions to the Administrator in your annual report if you had excess emissions during the reporting period. The excess emissions report must be submitted to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (<https://cdx.epa.gov/>.) You must use the appropriate electronic report in CEDRI for this subpart

or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (<https://www3.epa.gov/ttn/chief/cedri/>). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 days, you must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted. For the purpose of these reports, excess emissions are defined as specified in paragraphs (b)(1) and (2) of this section.

(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z).

(2) For any affected facility electing to comply with the provisions of §60.5407a(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of §60.5407a(b)(3). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours.

(c) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less than 2 LT/D of H₂S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H₂S expressed as sulfur.

(d) If you elect to comply with §60.5407a(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H₂S expressed as sulfur.

(e) The requirements of paragraph (b) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (b) of this section, provided that they comply with the requirements established by the state. Electronic reporting to the EPA cannot be waived, and as such, the provisions of this paragraph do not relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

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§60.5425a What parts of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

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§60.5430a What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VVa of part 60; and the following terms shall have the specific meanings given them.

Acid gas means a gas stream of hydrogen sulfide (H₂S) and carbon dioxide (CO₂) that has been separated from sour natural gas by a sweetening unit.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

API Gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

Artificial lift equipment means mechanical pumps including, but not limited to, rod pumps and electric submersible pumps used to flowback fluids from a well.

Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$$A = Y \times (B \div 100);$$

(2) The percent Y is determined from the following equation: $Y = 1.0 - 0.575 \log x$, where x is 2011 minus the year of construction; and

(3) The applicable basic annual asset guideline repair allowance, B, is 4.5.

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding \$25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including but not limited to general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.*, a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Collection system means any infrastructure that conveys gas or liquids from the well site to another location for treatment, storage, processing, recycling, disposal or other handling.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Completion combustion devices include pit flares.

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a compressor station for purposes of §60.5397a.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions.

Continuous bleed means a continuous flow of pneumatic supply natural gas to a pneumatic controller.

Crude oil and natural gas source category means:

- (1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and
- (2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.

Custody transfer means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Dehydrator means a device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber).

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

- (1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;
- (2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or
- (3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Equipment, as used in the standards and requirements in this subpart relative to the equipment leaks of GHG (in the form of methane) and VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this subpart.

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used transport field gas from a field to the main pipeline in the area.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

Flowback means the process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term flowback also means the fluids and entrained solids that emerge from a well during the flowback process. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage.

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §60.5411a, thief hatches or other openings on a controlled storage vessel not subject to §60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.

Gas processing plant process unit means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Greenfield site means a site, other than a natural gas processing plant, which is entirely new construction. Natural gas processing plants are not considered to be greenfield sites, even if they are entirely new construction.

Hydraulic fracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in §60.485a(e) or §60.5401a(f)(2).

In wet gas service means that a compressor or piece of equipment contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Initial flowback stage means the period during a well completion operation which begins at the onset of flowback and ends at the separation flowback stage.

Intermediate hydrocarbon liquid means any naturally occurring, unrefined petroleum liquid.

Intermittent/snap-action pneumatic controller means a pneumatic controller that is designed to vent non-continuously.

Liquefied natural gas unit means a unit used to cool natural gas to the point at which it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

Liquid collection system means tankage and/or lines at a well site to contain liquids from one or more wells or to convey liquids to another site.

Local distribution company (LDC) custody transfer station means a metering station where the LDC receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

Low pressure well means a well that satisfies at least one of the following conditions:

- (1) The static pressure at the wellhead following fracturing but prior to the onset of flowback is less than the flow line pressure at the sales meter;
- (2) The pressure of flowback fluid immediately before it enters the flow line, as determined under §60.5432a, is less than the flow line pressure at the sales meter; or
- (3) Flowback of the fracture fluids will not occur without the use of artificial lift equipment.

Maximum average daily throughput means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.

Natural gas-driven diaphragm pump means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump for purposes of this subpart. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

Natural gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Non-natural gas-driven pneumatic controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Produced water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

Qualified Professional Engineer means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under

this subpart. Professional engineers making these certifications must be currently licensed in at least one state in which the certifying official is located.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere, or other mechanism that provides the same function.

Recovered gas means gas recovered through the separation process during flowback.

Recovered liquids means any crude oil, condensate or produced water recovered through the separation process during flowback.

Reduced emissions completion means a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.

Reduced sulfur compounds means H₂S, carbonyl sulfide (COS), and carbon disulfide (CS₂).

Removed from service means that a storage vessel affected facility has been physically isolated and disconnected from the process for a purpose other than maintenance in accordance with §60.5395a(c)(1).

Returned to service means that a storage vessel affected facility that was removed from service has been:

- (1) Reconnected to the original source of liquids or has been used to replace any storage vessel affected facility; or
- (2) Installed in any location covered by this subpart and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process that is operational where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Salable quality gas means natural gas that meets the flow line or collection system operator specifications, regardless of whether such gas is sold.

Separation flowback stage means the period during a well completion operation when it is technically feasible for a separator to function. The separation flowback stage ends either at the startup of production, or when the well is shut in and permanently disconnected from the flowback equipment.

Startup of production means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water.

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of §60.5395a(c)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by §60.5420a(c)(5)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

(2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

Sulfur production rate means the rate of liquid sulfur accumulation from the sulfur recovery unit.

Sulfur recovery unit means a process device that recovers element sulfur from acid gas.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream.

Total Reduced Sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A-6 of this part.

Total SO₂ equivalents means the sum of volumetric or mass concentrations of the sulfur compounds obtained by adding the quantity existing as SO₂ to the quantity of SO₂ that would be obtained if all reduced sulfur compounds were converted to SO₂ (ppmv or kg/dscm (lb/dscf)).

Underground storage vessel means a storage vessel stored below ground.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well completion means the process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.

Well completion operation means any well completion with hydraulic fracturing or refracturing occurring at a well affected facility.

Well completion vessel means a vessel that contains flowback during a well completion operation following hydraulic fracturing or refracturing. A well completion vessel may be a lined earthen pit, a tank or other vessel that is skid-mounted or portable. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart.

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of the fugitive emissions standards at §60.5397a, well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries).

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

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§60.5432a How do I determine whether a well is a low pressure well using the low pressure well equation?

(a) To determine that your well is a low pressure well subject to §60.5375a(f), you must determine whether the characteristics of the well are such that the well meets the definition of

low pressure well in §60.5430a. To determine that the well meets the definition of low pressure well in §60.5430a, you must use the low pressure well equation below:



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Where:

- (1) P_L is the pressure of flowback fluid immediately before it enters the flow line, expressed in pounds force per square inch (psia), and is to be calculated using the equation above;
 - (2) P_R is the pressure of the reservoir containing oil, gas, and water at the well site, expressed in psia;
 - (3) L is the true vertical depth of the well, expressed in feet (ft);
 - (4) q_o is the flow rate of oil in the well, expressed in cubic feet/second (cu ft/sec);
 - (5) q_g is the flow rate of gas in the well, expressed in cu ft/sec;
 - (6) q_w is the flow rate of water in the well, expressed in cu ft/sec;
 - (7) ρ_o is the density of oil in the well, expressed in pounds mass per cubic feet (lbm/cu ft).
- (b) You must determine the four values in paragraphs (a)(4) through (7) of this section, using the calculations in paragraphs (b)(1) through (b)(15) of this section.
- (1) Determine the value of the bottom hole pressure, P_{BH} (psia), based on available information at the well site, or by calculating it using the reservoir pressure, P_R (psia), in the following equation:



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- (2) Determine the value of the bottom hole temperature, T_{BH} (F), based on available information at the well site, or by calculating it using the true vertical depth of the well, L (ft), in the following equation:

$$T_{BH} (F) = (0.014 \times L) + 79.081$$

- (3) Calculate the value of the applicable natural gas specific gravity that would result from a separator pressure of 100 psig, γ_{gs} , using the following equation with: Separator at standard conditions (pressure, $p = 14.7$ (psia), temperature, $T = 60$ (F)); the oil API gravity at the well site, γ_o ; and the gas specific gravity at the separator under standard conditions, $\gamma_{sp} = 0.75$:

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(4) Calculate the value of the applicable dissolved GOR, R_s ($scf/STBO$), using the following equation with: The bottom hole pressure, P_{BH} ($psia$), determined in (b)(1) of this section; the bottom hole temperature, T_{BH} (F), determined in (b)(2) of this section; the gas gravity at separator pressure of 100 psig, γ_{gs} , calculated in (b)(3) of this section; the oil API gravity, γ_o , at the well site; and the constants, C1, C2, and C3, found in Table A:

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Table A—Coefficients for the correlation for R_s

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C1	0.0362	0.0178
C2	1.0937	1.1870
C3	25.7240	23.931

(5) Calculate the value of the oil formation volume factor, B_o ($bbl/STBO$), using the following equation with: the bottom hole temperature, T_{BH} (F), determined in paragraph (b)(2) of this section; the gas gravity at separator pressure of 100 psig, γ_{gs} , calculated in paragraph (b)(3) of this section; the dissolved GOR, R_s ($scf/STBO$), calculated in paragraph (b)(4) of this section; the oil API gravity, γ_o , at the well site; and the constants, C1, C2, and C3, found in Table B:

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Table B—Coefficients for the Correlation for B_o

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C1	4.677×10^{-4}	4.670×10^{-4}
C2	1.751×10^{-5}	1.100×10^{-5}
C3	-1.811×10^{-8}	1.337×10^{-9}

(6) Calculate the density of oil at the wellhead,

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using the following equation with the value of the oil API gravity, γ_o , at the well site:

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(7) Calculate the density of oil at bottom hole conditions,

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using the following equation with: the dissolved GOR, R_s (scf/ STBO), calculated in paragraph (b)(4) of this section; the oil formation volume factor, B_o (bbl/ STBO), calculated in paragraph (b)(5) of this section; the oil density at the wellhead,

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calculated in paragraph (b)(6) of this section; and the dissolved gas gravity, $\gamma_{gd} = 0.77$:

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(8) Calculate the density of oil in the well,

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using the following equation with the density of oil at the wellhead,

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calculated in paragraph (b)(6) of this section; and the density of oil at bottom hole conditions,

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calculated in paragraph (b)(7) of this section:

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(9) Calculate the oil flow rate, q_o (cu ft/sec,) using the following equation with: the oil formation volume factor, Bo (bbl/ STBO), as calculated in paragraph (b)(5) of this section; and the estimated oil production rate at the well head, Q_o (STBO/ day):

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(10) Calculate the critical pressure, P_c (psia), and critical temperature, T_c (R), using the equations below with: Gas gravity at standard conditions (pressure, $P = 14.7$ (psia), temperature, $T = 60$ (F)), $\gamma = 0.75$; and where the mole fractions of nitrogen, carbon dioxide and hydrogen sulfide in the gas are $X_{N_2} = 0.168225$, $X_{CO_2} = 0.013163$, and $X_{H_2S} = 0.013680$, respectively:

$$P_c(\text{psia}) = 678 - 50 \cdot (\gamma_g - 0.5) - 206.7 \cdot X_{N_2} + 440 \cdot X_{CO_2} + 606.7 \cdot X_{H_2S}$$

$$T_c(\text{R}) = 326 + 315.7 \cdot (\gamma_g - 0.5) - 240 \cdot X_{N_2} - 88.3 \cdot X_{CO_2} + 133.3 \cdot X_{H_2S}$$

(11) Calculate reduced pressure, P_r , and reduced temperature, T_r , using the following equations with: the bottom hole pressure, P_{BH} , as determined in paragraph (b)(1) of this section; the bottom hole temperature, T_{BH} (F), as determined in paragraph (b)(2) of this section in the following equations:

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(12)(i) Calculate the gas compressibility factor, Z , using the following equation with the reduced pressure, P_r , calculated in paragraph (b)(11) of this section:

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(ii) The values for A, B, C, D in the above equation, are calculated using the following equations with the reduced pressure, P_r , and reduced temperature, T_r , calculated in paragraph (b)(11) of this section:



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(13) Calculate the gas formation volume factor,

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using the bottom hole pressure, P_{BH} (*psia*), as determined in paragraph (b)(1) of this section; and the bottom hole temperature, T_{BH} (*F*), as determined in paragraph (b)(2) of this section:

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(14) Calculate the gas flow rate,

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using the following equation with: the value of gas formation volume factor,

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calculated in paragraph (b)(13) of this section; the estimated gas production rate, Q_g (*scf/ day*); the estimated oil production rate, Q_o (*STBO/ day*); and the dissolved GOR, R_s (*scf/ STBO*), as calculated in paragraph (b)(4) of this section:

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(15) Calculate the flow rate of water in the well, q_w (*cu ft/sec*), using the following equation with the water production rate Q_w (*bbl/day*) at the well site:

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§§60.5433a-60.5499a [Reserved]

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Table 1 to Subpart OOOOa of Part 60—Required Minimum Initial SO₂ Emission Reduction Efficiency (Z_i)

H ₂ S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	2.0 < X < 5.0	5.0 < X < 15.0	15.0 < X < 300.0	X > 300.0
Y > 50	79.0	88.51X ^{0.0101} Y ^{0.0125} or 99.9, whichever is smaller.		
20 < Y < 50	79.0	88.51X ^{0.0101} Y ^{0.0125} or 97.9, whichever is smaller		97.9
10 < Y < 20	79.0	88.51X ^{0.0101} Y ^{0.0125} or 93.5, whichever is smaller	93.5	93.5
Y < 10	79.0	79.0	79.0	79.0

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Table 2 to Subpart OOOOa of Part 60—Required Minimum SO₂ Emission Reduction Efficiency (Z_c)

H ₂ S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	2.0 < X < 5.0	5.0 < X < 15.0	15.0 < X < 300.0	X > 300.0
Y > 50	74.0	85.35X ^{0.0144} Y ^{0.0128} or 99.9, whichever is smaller.		
20 < Y < 50	74.0	85.35X ^{0.0144} Y ^{0.0128} or 97.5, whichever is smaller		97.5
10 < Y < 20	74.0	85.35X ^{0.0144} Y ^{0.0128} or 90.8, whichever is smaller	90.8	90.8
Y < 10	74.0	74.0	74.0	74.0

X = The sulfur feed rate from the sweetening unit (*i.e.*, the H₂S in the acid gas), expressed as sulfur, Mg/D(LT/D), rounded to one decimal place.

Y = The sulfur content of the acid gas from the sweetening unit, expressed as mole percent H₂S (dry basis) rounded to one decimal place.

Z = The minimum required sulfur dioxide (SO₂) emission reduction efficiency, expressed as percent carried to one decimal place. Z_i refers to the reduction efficiency required at the initial

performance test. Z_c refers to the reduction efficiency required on a continuous basis after compliance with Z_i has been demonstrated.

As stated in §60.5425a, you must comply with the following applicable General Provisions:

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Table 3 to Subpart OOOOa of Part 60—Applicability of General Provisions to Subpart OOOOa

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.5430a.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and record keeping	Yes	Except that §60.7 only applies as specified in §60.5420a(a).
§60.8	Performance tests	Yes	Performance testing is required for control devices used on storage vessels, centrifugal compressors and pneumatic pumps.
§60.9	Availability of information	Yes	
§60.10	State authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart OOOOa.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Continuous monitors are required for storage vessels.
§60.14	Modification	Yes	To the extent any provision in §60.14 conflicts with specific provisions in subpart

			OOOOa, it is superseded by subpart OOOOa provisions.
§60.15	Reconstruction	Yes	Except that §60.15(d) does not apply to wells, pneumatic controllers, pneumatic pumps, centrifugal compressors, reciprocating compressors or storage vessels.
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device and work practice requirements	Yes	
§60.19	General notification and reporting requirement	Yes	

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GENERAL PLAN APPROVAL AND/OR GENERAL OPERATING PERMIT BAQ-GPA/GP-5

Natural Gas Compression Stations, Processing Plants, and Transmission Stations

SECTION A. GENERAL REQUIREMENTS

1. Statutory/Regulatory Authority and General Description

In accordance with Section 6.1(f) of the Pennsylvania Air Pollution Control Act (APCA), 35 P.S. § 4006.1(f) and 25 Pa. Code Chapter 127, Subchapter H, the Department of Environmental Protection (Department or DEP) hereby issues this General Plan Approval and/or General Operating Permit (General Permit or GP-5) for new or modified natural gas compressor stations, processing plants, and transmission stations (facility or facilities) constructed, modified, or operated in this Commonwealth.

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3. Definitions

Words and terms that are not otherwise defined in this General Permit shall have the meanings set forth in Section 3 of the APCA (35 P.S. § 4003) and Title 25, Article III including 25 Pa. Code § 121.1 unless the context indicates otherwise. The meanings set forth in applicable definitions codified in the Code of Federal Regulations (CFR), including 40 CFR Part 60, Subparts KKK, JJJJ, KKKK, OOOO, and OOOOa or 40 CFR Part 63, Subparts HH and ZZZZ, shall also apply to this General Permit.

Coal Bed Methane – Methane that is extracted from a coal bed and the surrounding rock strata by extraction wells drilled in advance of a mining operation, which is typically of pipeline quality.

Fugitive Emissions Component – Any component that has the potential to emit fugitive emissions of methane, Volatile Organic Compounds (VOC), or Hazardous Air Pollutants (HAP) at a natural gas compressor station, processing plant, or transmission station including, but not limited to, valves, connectors, pressure relief devices, open-ended lines, flanges, compressors, instruments, meters, covers, and closed vent systems. Devices that vent as part of normal operations are not considered fugitive sources unless the emission originates from a place other than the vent.

Gob Gas – Methane that is mixed with air from a mine ventilation system due to the mining operation reaching the area of an extraction well, which is typically below pipeline quality.

Leak – A leak is defined as any release of gaseous hydrocarbons that is detected by Auditory, Visual, or Olfactory (AVO) inspection; an optical gas imaging (OGI) camera calibrated according to 40 CFR § 60.18 and a detection sensitivity level of 60 grams/hour; a gas leak detector that meets the requirements of 40 CFR Part 60, Appendix A-7, Method 21 that detects a concentration of 500 ppm calibrated as methane or greater; or other leak detection methods approved by the Department's Division of Source Testing and Monitoring. However, a release from any equipment or component designed by the manufacturer to protect the equipment, controller, or personnel or to prevent groundwater contamination, gas migration, or an emergency situation is not considered a leak.

Natural Gas Compressor Station – A facility that compresses and/or processes natural gas, coal bed methane, or gob gas prior to the point of custody transfer using processes including, but not limited to, gas dehydration, compression, pigging, and storage.

Natural Gas Processing Plant – A facility that engages in the extraction of natural gas liquids from field gas, the fractionation of mixed natural gas liquids to natural gas products, or both extracts and fractionates natural gas liquids.

Natural Gas Transmission Station – A facility that compresses and/or processes natural gas after the point of custody transfer using processes including, but not limited to, gas dehydration, compression, pigging, and storage.

Pigging Operations – The process of removing and collecting condensed liquids including condensate, intermediate hydrocarbons, or produced water, from a pipeline using a spherical or bullet-shaped device, known as a pig, forced through the pipeline by natural gas pressure. The liquids are then collected at their eventual destination in a storage tank, often referred to as a slug tank. This process also includes an operation conducted for a pipeline integrity evaluation.

Point of Custody Transfer – The location after the processing and/or treatment of natural gas in the production sector, typically after a natural gas processing plant, where control and/or ownership of the natural gas is transferred from one owner or operator to another.

Sour Gas – Natural gas where the Hydrogen Sulfide (H₂S) content is in excess of 4 ppmv at standard temperature and pressure.

4. Applicability/Scope

- (a) This General Permit authorizes the construction, modification, and/or operation of a natural gas compressor station, processing plant, or transmission station. The applicability of this General Permit may include one or more of the following operations or emission sources:
- (i) Glycol Dehydration Units
 - (ii) Stationary Natural Gas-Fired Spark Ignition Internal Combustion Engines
 - (iii) Reciprocating Compressors
 - (iv) Storage Vessels
 - (v) Tanker Truck Load-Out Operations
 - (vi) Fugitive Emissions Components
 - (vii) Natural Gas-Driven Pneumatic Controllers
 - (viii) Natural Gas-Driven Pneumatic Pumps
 - (ix) Enclosed Flares and Other Emission Control Devices
 - (x) Pigging Operations

- (xi) Natural Gas-Fired Combustion Units
 - (xii) Stationary Natural Gas-Fired Combustion Turbines
 - (xiii) Centrifugal Compressors
- (b) An Application for Authorization to Use GP-5 may be submitted for the operation of an eligible source if the source is exempted from plan approval requirements under 25 Pa. Code § 127.14.
- (c) If any source located at the facility cannot be regulated under this General Permit, a plan approval and/or an operating permit issued in accordance with 25 Pa. Code, Chapter 127, Subchapter B and/or Subchapter F will be required.

5. Prohibited Use of GP-5

GP-5 may not be used for the construction, modification, or operation of any of the following air contamination sources:

- (a) A proposed source located at a Title V facility including sources determined to be a single source Title V facility.
- (b) A proposed source that is subject to Title V permitting requirements specified in 25 Pa. Code Chapter 127, Subchapters F and G; prevention of significant deterioration requirements specified in 25 Pa. Code Chapter 127 Subchapter D; or nonattainment new source review requirements specified in 25 Pa. Code Chapter 127 Subchapter E.
- (c) A facility that produces or processes sour gas.
- (d) *Circumvention.*
 - (i) The owner or operator of a facility may not circumvent the new source review requirements of 25 Pa. Code Chapter 127, Subchapter E by causing or allowing a pattern of ownership or development, including the phasing, staging, delaying, or engaging in incremental construction over a geographic area of a facility which, except for the pattern of ownership or development, would otherwise require a permit or submission of a plan approval application.
 - (ii) No person may permit the use of a device, stack height that exceeds good engineering practice, dispersion technique, or other technique that, without resulting in reduction of the total amount of air contaminants emitted, conceals or dilutes an emission of air contaminants that would otherwise be in violation of this General Permit, the APCA, or the regulations promulgated thereunder, except for those that are used for the control of malodors with the prior written approval of the Department.

6. Authorization to Use GP-5

- (a) *Application for Authorization to Use GP-5.* Pursuant to 25 Pa. Code § 127.621, any person proposing to construct, operate, or modify a source listed in Section A, Condition 4 of this General Permit at a natural gas compressor station, processing plant, or transmission station shall submit an Application for Authorization to Use GP-5 to the Air Program Manager of the appropriate DEP Regional Office responsible for authorizing the use of the General Permit in the county in which the facility will be located. This application shall be submitted to DEP either through the e-Permitting system, by hand delivery, courier, or sent to DEP by certified mail, return receipt requested, in accordance with 25 Pa. Code § 127.621(b).
- (b) *Terms of Authorization to Use GP-5.* This General Permit authorizes the construction and/or operation of the specific sources at the specific facility as described in the application for a term of five years from the date of authorization. The authorization to construct a source or facility will expire 18 months from the date of the authorization if the owner or operator fails to commence construction or if there is a lapse in construction of 18 months. The Department may extend the 18-month period upon an owner or operator providing satisfactory justification for an extension up to the original date of the five-year term. All requests for extension shall be submitted to the Department at least 30 days prior to the end of the 18-month period and are only valid upon receipt of written approval by the Department. The expiration of the authorization to construct will require a new Application for Authorization to Use GP-5 if an extension is not requested and granted.
- (c) *Expiration of and Re-Authorization to Use GP-5.*
 - (i) The authorization granted by the Department to construct and/or operate under this General Permit shall terminate on the date of expiration unless a complete Application for Authorization to Use GP-5 is submitted to the Department at least 30 calendar days prior to the expiration date.

- (ii) Upon receipt by the Department of a timely, administratively and technically complete application for re-authorization to operate under this General Permit, the owner or operator may continue to operate the facility subject to final action by the Department provided that the sources and the facility are operated in compliance with the terms and conditions of this General Permit. The Authorization to Use GP-5 shall cease if the owner or operator fails to submit any additional information requested by the Department to process the application by the specified deadline.
- (d) *Transfer of Ownership.* The Authorization to Use GP-5 may not be transferred from the owner or operator of a facility except when the change of ownership is demonstrated to the satisfaction of the Department and the Department approves the transfer in writing. Within 30 calendar days after a transfer of ownership of the facility, the new owner or operator shall submit an appropriate form or application to the Air Program Manager of the appropriate Regional Office. If the owner or operator is modifying any existing source or adding a new source at the facility currently authorized by the General Permit, the owner or operator shall submit an Application for Authorization to Use GP-5 in accordance with Condition 6(a) above. If there are equipment or activities located on the same site or on sites that share equipment and are within $\frac{1}{4}$ mile of each other, the owner or operator shall submit an Application for Authorization to use GP-5 as a General Plan Approval with a \$1,000 application fee. If the owner or operator is not modifying any existing source, not adding a new source, or not subject to a new Single Source Determination based on the transfer of ownership, the owner or operator shall submit a Transfer of Ownership form with a \$300 fee. The employer I.D. number (Federal IRS No.) shall be used as a test to determine if a transfer of ownership has occurred.
- (e) *Administrative Amendment.* In the event of a change in the name, address, or telephone number of a person identified in the General Permit Application or a similar minor administrative change at the facility, the Department may authorize an administrative amendment. The owner or operator shall submit a brief description of the change and the date on which the change is to occur in a letter signed by the Responsible Official with the fee specified in Condition 7(e) to the Air Program Manager of the appropriate Regional Office.
- (f) *Modification, Suspension, or Revocation of GP-5 or Authorizations to Use GP-5.*
 - (i) The Department may modify, suspend, or revoke and reissue this General Permit if it is determined that GP-5 does not comply with the Clean Air Act, the APCA, or regulations adopted under the acts.
 - (ii) This General Permit may be modified, suspended, or revoked if the Department determines that the natural gas compressor station, processing plant, or transmission station cannot be adequately regulated under this General Permit.
 - (iii) An Authorization to Use GP-5 may be suspended or revoked if the Department determines that, at any time, the owner or operator has failed to construct and/or operate the facility in compliance with the terms and conditions of this General Permit, the specifications in the Application for Authorization to Use GP-5, or the information provided in the supplemental material included with the application used to determine if the proposed sources will comply with the GP-5.
 - (iv) Upon suspension or revocation of an Authorization to Use GP-5, the owner or operator shall immediately cease construction and/or operation of the facility. The owner or operator of the facility shall not restart construction and/or operation prior to the receipt of written approval from the Department.

7. General Permit Fees

Each applicant seeking Authorization to Use GP-5 shall submit the applicable fees required under this Condition to the appropriate DEP Regional Office. The following fee schedules apply to this General Permit:

- | | |
|--|---------|
| (a) General Plan Approval Application Fee for Sources Subject to and Review of NSPS, payable upon submission of the application: | \$1,700 |
| (b) General Plan Approval Application Fee with new Single Source Determination, payable upon submission of the application: | \$1,000 |
| (c) General Operating Permit Application Fee, payable upon submission of the application: | \$ 375 |
| (d) Annual Operating Permit Administration Fee, payable by March 1 st for the previous calendar year: | \$ 375 |
| (e) Administrative Amendment Fee, payable upon submission of the letter in Condition 6(e): | \$ 300 |

- (f) The Department may increase the applicable fees for this General Plan Approval/General Operating Permit in accordance with the applicable fee schedules in 25 Pa. Code Chapter 127, Subchapter I, following notice in the *Pennsylvania Bulletin*.

8. Applicable Laws

- (a) It is the duty of the Responsible Official, as defined in 25 Pa. Code § 121.1, to ensure that the facility is in compliance with all applicable federal, state, and local laws and regulations, including 25 Pa. Code, Subpart C, Article III. Nothing in this General Permit relieves the Responsible Official from this obligation to comply.
- (b) Applicable federal regulations may include, but are not limited to, the following New Source Performance Standards (NSPS), codified at 40 CFR Part 60 and incorporated by reference in 25 Pa. Code § 122.3, and National Emission Standards for Hazardous Air Pollutants (NESHAP), codified at 40 CFR Part 63 and incorporated by reference in 25 Pa. Code § 127.35:
- (i) **40 CFR Part 60, Subpart KKK** – Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants for which Construction, Reconstruction, or Modification Commenced After January 20, 1984, and on or before August 23, 2011.
 - (ii) **40 CFR Part 60, Subpart JJJJ** – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.
 - (iii) **40 CFR Part 60, Subpart KKKK** – Standards of Performance for Stationary Combustion Turbines.
 - (iv) **40 CFR Part 60, Subpart OOOO** – Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution for which Construction, Modification, or Reconstruction Commenced after August 23, 2011, and on or before September 18, 2015.
 - (v) **40 CFR Part 60, Subpart OOOOa** – Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015.
 - (vi) **40 CFR Part 63, Subpart HH** – National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities.
 - (vii) **40 CFR Part 63, Subpart ZZZZ** – National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines.

9. Best Available Technology Requirements

New sources are required to control the emission of air pollutants to the maximum extent, consistent with best available technology (BAT) as determined by the Department as of the date of issuance of the plan approval for the new source as required under 25 Pa. Code § 127.1. Condition 1 (BAT Compliance Requirements) of Sections B through N of this General Permit are determined to meet the BAT requirements.

10. Compliance Requirements and Compliance Certification

- (a) The emissions from all sources and associated air pollution control equipment located at a natural gas compressor station, processing plant, or transmission station and other sources determined by the Department to be a single source shall not equal or exceed either of the following on a 12-month rolling sum basis:
- (i) Nitrogen Oxides (NO_x) – 100 tons
 - (ii) Carbon Monoxide (CO) – 100 tons
 - (iii) Sulfur Oxides (SO_x) – 100 tons
 - (iv) Particulate Matter with an aerodynamic diameter less than 10 microns (PM₁₀) – 100 tons
 - (v) Particulate Matter with an aerodynamic diameter less than 2.5 microns (PM_{2.5}) – 100 tons
 - (vi) Volatile Organic Compounds (VOC) – 50 tons
 - (vii) Any individual Hazardous Air Pollutant (HAP) – 10 tons
 - (viii) Total Hazardous Air Pollutants (HAP) – 25 tons

- (ix) In addition, the emissions from all sources and associated air pollution control equipment located at a facility in Bucks, Chester, Delaware, Montgomery, or Philadelphia Counties shall not equal or exceed any of the following on a 12-month rolling sum basis:
 - (A) NO_x – 25 tons
 - (B) VOC – 25 tons
- (b) The facility throughput, hours of operation, and/or emissions from sources at the facility shall be constrained as necessary to not exceed any facility-wide emissions cap required in (a) above.
- (c) All sources and associated air pollution control equipment located at a facility shall be:
 - (i) Operated in such a manner as not to cause air pollution, as that term is defined in 25 Pa. Code § 121.1;
 - (ii) Operated and maintained in accordance with the manufacturer's specifications, procedures, and recommended maintenance schedule, as provided in the Application for Authorization to Use GP-5, or an alternate procedure approved by the Department that achieves equal or greater emissions reductions in accordance with 25 Pa. Code § 127.12b;
 - (iii) Operated and maintained in accordance with the fugitive emission requirements of 25 Pa. Code § 123.1 and § 123.2; **and**
 - (iv) Operated and maintained in such a manner that malodors are not detectable outside the property of the owner or operator on whose land the facility is being operated in accordance with 25 Pa. Code § 123.31.
- (d) The owner or operator of an existing facility where a new source is installed or there is a modification of an existing source, shall comply with the applicable BAT requirements established in this General Permit.
- (e) This General Permit cannot be used to relax BAT or other emission limitations or requirements previously established through the air quality permitting process.
- (f) An owner or operator of a facility may apply to the Department for a plan approval for any air contamination source in lieu of seeking authorization to use the General Permit for natural gas compressor stations, processing plants, or transmission stations.
- (g) The owner or operator authorized to use this General Permit shall comply with the specifications in the application and the terms and conditions of this General Permit.
- (h) The owner or operator of the facility shall submit to the Air Program Manager of the appropriate DEP Regional Office an annual certification of compliance with the terms and conditions in the GP-5 for the previous year, including the emission limitations, standards, or work practices. This Compliance Certification Form must be included in the annual report as outlined in Condition 13(c)(vi).

11. Notification Requirements

- (a) *Municipal Notification.* The facility owner or operator proposing to use this General Permit shall notify the local municipality and county where the air pollution source is to be located that they have applied for an Authorization to Use GP-5. The notification shall clearly describe the proposed sources and/or modifications.
- (b) The owner or operator shall notify the Air Program Manager of the appropriate DEP Regional Office, in writing, at least five business days prior to the commencement of operation of a source of their intent to do so. The owner or operator shall also include the date of completion of construction of the source in the notice. When multiple sources at the facility are subject to different commencement of operation schedules, written notice shall be submitted to DEP prior to the commencement of operation of each source.
- (c) *Malfunctions.*
 - (i) Any malfunction that poses an imminent danger to the public health, safety, or welfare or to the environment shall be reported by telephone to the County Emergency Management Agency and to the 24-hour Emergency Hotline at 1-800-541-2050 no later than one hour after the discovery of an incident. Following the telephone or email notification, a written notice as specified in (iv) below shall be submitted to DEP within three business days.
 - (ii) Any malfunction that does not pose an imminent danger to the public health, safety, or welfare or to the environment shall follow the guidance provided in the [GP-5 and GP-5A Malfunction Reporting Instructions](#)

and, if required to report, shall notify the Air Program Manager of the appropriate DEP Regional Office by telephone or email within 24 hours of discovery. Following the telephone or email notification, a written notice as specified in (iv) below shall be submitted to DEP within five business days.

- (iii) If the owner or operator is unable to provide notification by telephone to the Air Program Manager of the appropriate DEP Regional Office within 24 hours of the discovery of a malfunction due to a weekend or holiday, the notification shall be made to the Department no later than 4:00 pm on the first business day following the weekend or holiday.
- (iv) Written notification shall include:
 - (A) The name, GP-5 authorization number, and location of the facility;
 - (B) The nature and cause of the malfunction or incident;
 - (C) The date and time when the malfunction, incident, or breakdown was first discovered;
 - (D) The expected duration of increased emissions;
 - (E) The estimated rate of emissions for all criteria, hazardous, and greenhouse gas pollutants; and
 - (F) Any changes to the equipment or modification of the procedures that will prevent reoccurrences of the malfunction.
- (v) The owner or operator shall notify the Air Program Manager of the appropriate DEP Regional Office by telephone or email within 24 hours of when corrective measures have been implemented.
- (vi) Any emissions due to a malfunction are to be reported in the annual emissions inventory report required in Condition 13(d).

12. Recordkeeping Requirements

- (a) All records required must be maintained onsite or at the nearest local field office for a minimum of 5 years and may be maintained in electronic format.
- (b) The owner or operator of the facility shall generate and maintain records that clearly demonstrate to the Department that the facility is not a Title V facility and that the facility is in compliance with facility-wide emission limitations. At a minimum, the records shall be maintained on a monthly basis, and the actual emissions shall be calculated on a 12-month rolling sum. The Department reserves the right to request additional information necessary to determine compliance with the General Permit.
- (c) The owner or operator of the facility shall keep records of all written notifications required under permit conditions.

13. Reporting Requirements

- (a) The owner or operator of a natural gas compressor station, processing plant, or transmission station shall submit to the Air Program Manager of the appropriate DEP Regional Office all requests, reports, applications, submittals, and other communications concerning applicable federal NSPS and NESHAP.
- (b) In accordance with 40 CFR §§ 60.4 and 63.10, copies of all requests, reports, applications, submittals, and other communications shall also be submitted to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI) accessible at <https://cdx.epa.gov> unless electronic reporting is not available, in which case a copy shall be sent to the following address:

United States Environmental Protection Agency, Region III
Office of Air Enforcement and Compliance Assistance (3AP20)
1650 Arch St.
Philadelphia, PA 19103-2029

- (c) The annual report is required to be submitted either in electronic format, by hand-delivery, courier, or sent by certified mail, return receipt requested, to the Air Program Manager of the appropriate DEP Regional Office, the reporting period specified by the owner/operator shall be no later than one year from the start of operations of the facility, unless otherwise approved by the Department. The initial and subsequent annual reports shall be submitted within 60 days of the end of the reporting periods. General information required on all reports includes:
 - (i) Company Name;

- (ii) Facility Site Name;
 - (iii) The GP-5 authorization number;
 - (iv) Either:
 - (A) The address of the site; or
 - (B) A description of the site and the location using latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of 5 decimal degrees using the North American Datum of 1983;
 - (v) The beginning and ending dates of the reporting period;
 - (vi) The Certification Form described in Condition 10(h), which must include:
 - (A) The statement: "Based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."; and
 - (B) The signature of the certifying Responsible Official;
 - (vii) Identification of each source included in the report;
 - (viii) The identification of each term or condition of the GP-5 that is the basis of the certification, the compliance status, and the methods used for determining the compliance status of the source, currently and over the reporting period as identified in Sections B through N of this General Permit; and
 - (ix) The records of the facility's emissions to demonstrate compliance with Condition 12(b).
- (d) In accordance with 25 Pa. Code § 135.3, the owner or operator of a facility shall submit to the Department via AES*Online or AES*XML at www.depgreenport.state.pa.us/ by March 1st of each year, a facility inventory report for the preceding calendar year for all sources regulated under this General Permit. The inventory report shall include all emissions information for all sources operated during the preceding calendar year from the annual report required in (c) above. Emissions data including, but not limited to, the following shall be reported:
- (i) NO_x;
 - (ii) CO;
 - (iii) SO_x;
 - (iv) PM₁₀;
 - (v) PM_{2.5};
 - (vi) VOC;
 - (vii) Speciated HAP including, but not limited to, benzene, ethyl benzene, formaldehyde, n-hexane, toluene, isomers and mixtures of xylenes, and 2,2,4-trimethylpentane;
 - (viii) Total HAP;
 - (ix) CO₂;
 - (x) CH₄; and
 - (xi) N₂O.

14. Source Testing Requirements

- (a) In addition to the specific performance testing requirements included in this General Permit, the Department may require the owner or operator to conduct a source test if it is determined that the air contaminant emissions from a source operating under this General Permit are, or may be, in excess of an applicable air contaminant emission limitation.
- (b) The Department may alter the frequency of performance test requirements for reauthorization based on available performance data from the source, unless required by federal regulation.

- (c) All testing, with the exception of periodic monitoring, shall be performed in accordance with any applicable federal regulations, 25 Pa. Code, Chapter 139, and the current version of the Department's Source Testing Manual, or an alternative test method as approved by the Department.
- (d) All submittals, with the exception of periodic monitoring data, shall meet the applicable requirements specified in the most current version of the Department's Source Testing Manual.
- (e) One electronic copy **and** one printed copy of all reports, protocols, and test completion notifications, with the exception of periodic monitoring data, shall be submitted either by hand-delivery, courier, or sent by certified mail, return receipt requested, to the Air Program Manager of the appropriate DEP Regional Office **and** to the PSIMS Administrator for the Source Testing Section in DEP's Central Office.
- (f) At least 60 calendar days prior to commencing an emission testing program to demonstrate compliance required by this General Permit, a Test Protocol shall be submitted in accordance with (e) above for review and approval. An operator may request an approval from the Department for a test protocol that covers testing of all currently operated sources in service at that operator's various facilities. In such a request, the operator will submit the test protocol in accordance with (e) above for review and approval and include a list of currently permitted sources. If the owner or operator has a test protocol, previously approved by the Department, a new test protocol does not need to be submitted for review/approval, provided that there are no changes, including the testing contractor, and the owner/operator agrees to comply with all conditions of acceptance in the letter approving the protocol.
- (g) At least 30 calendar days prior to commencing an emission testing program to demonstrate compliance required by this General Permit, written notification of the date and time of testing shall be provided to the Department's Division of Source Testing and Monitoring and the appropriate DEP Regional Office so that an observer may be present. The Department is under no obligation to accept the results of any testing performed without adequate advance written notice to the Department of such testing.
- (h) Within 15 calendar days after completion of the on-site testing portion of an emission test program to demonstrate compliance required by this General Permit, if a complete test report has not yet been submitted, an electronic notification shall be submitted in accordance with (e) above indicating the completion date of the on-site testing.
- (i) A complete test report shall be submitted in accordance with (e) above no later than 60 calendar days after completion of the on-site testing portion of an emission test program required by this General Permit. The complete test report shall include a summary at the beginning of the report which includes:
 - (i) A statement that the owner or operator has reviewed the report from the emissions testing company and agrees with the findings;
 - (ii) The GP-5 authorization number and conditions that are the basis for the evaluation;
 - (iii) A summary of results with respect to each applicable permit condition; **and**
 - (iv) A statement of compliance or non-compliance with each applicable permit condition.

15. De Minimis Emission Increases

- (a) Additional equipment may be installed, or currently authorized equipment may be modified at the facility without additional authorization provided that the following conditions (i) through (iii) are met. Replacement unit as defined in 25 Pa. Code § 121.1 may be installed without additional authorization provided that the following conditions (ii) through (iii) are met.
 - (i) The owner or operator complies with the requirements of 25 Pa. Code § 127.449(a), (b), and (d) through (i);
 - (ii) The equipment being installed, modified, or replaced meets the current applicable BAT Compliance Requirements;
 - (iii) The owner or operator submits written notification in accordance with Condition 11(b), including the following additional information:
 - (A) The manufacturer, model, rated capacity, and serial number of the equipment;
 - (B) A certification from the owner or operator that the equipment will meet all applicable terms and conditions of this General Permit, including Condition 10(a);

- (C) The notification shall be signed by a Responsible Official and shall acknowledge that the certifying party is aware of the penalties for unsworn falsification to governmental authorities as established under 18 Pa. C.S. § 4904. The certification shall also state that based on information and belief formed after reasonable inquiry, that the information in the notice is true, accurate, and complete; **and**
 - (D) The notice shall identify and describe the pollutants that will be emitted as a result of the de minimis emissions increase and provide emission rates in tons per year and in terms necessary to establish compliance with any applicable requirement.
- (b) A new Authorization to Use GP-5 shall be required if an owner or operator chooses to employ Selective Catalytic Reduction (SCR) to comply with NO_x emission standards in Section C Condition 1(c) or Section M Condition 1(c).

SECTION B. GLYCOL DEHYDRATION UNITS

1. BAT Compliance Requirements

- (a) For each glycol dehydration unit constructed and operated under an Authorization to Use GP-5 approved by the Department prior to February 2, 2013, with a total uncontrolled potential VOC emission rate greater than 10 tpy, the owner or operator shall control VOC emissions from the glycol dehydrator still vent stream by at least 85% with a condenser, flare, thermal oxidizer, vapor recovery unit, or other air cleaning device approved by the Department that meets the applicable requirements in Section J.
- (b) For each glycol dehydration unit constructed and authorized to operate on or after February 2, 2013, but prior to August 8, 2018, with a total uncontrolled potential VOC emission rate of greater than 5 tpy, the owner or operator shall control VOC emissions from the glycol dehydrator still vent stream by at least 95% with a condenser, flare, thermal oxidizer, vapor recovery unit, or other air cleaning device approved by the Department that meets the applicable requirements in Section J.
- (c) For each glycol dehydrator constructed and authorized to operate on or after August 8, 2018, with a methane emission rate of 200 tpy or greater, a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, the owner or operator shall control methane, VOC, and HAP emissions from the glycol dehydrator still vent stream by at least 95% using an enclosed flare or other combustion device or other air cleaning device approved by the Department that meets the applicable requirements in Section J.
- (d) Associated equipment, such as natural gas-driven pneumatic controllers (Section H), natural gas-driven pneumatic pumps (Section I), and fugitive emissions components (Section G) are subject to the requirements of their respective Sections.
- (e) If any glycol dehydration unit uses triethylene glycol for the dehydration process, has a natural gas throughput greater than 3 MMscf/d, **and** emits more than 1 tpy of benzene, the owner or operator must:
 - (i) Determine the natural gas throughput in accordance with 40 CFR § 63.772(b)(1).
 - (ii) Determine the actual average benzene or benzene, toluene, ethylbenzene and xylene (BTEX) emissions in accordance with 40 CFR § 63.772(b)(2).
 - (iii) If the glycol dehydration unit is located at a facility located within an urbanized area plus offset or urban cluster boundary, the owner or operator shall meet the requirements of 40 CFR § 63.764(d)(1).
 - (iv) If the glycol dehydration unit is located at a facility that is not within an urbanized area plus offset or urban cluster boundary, the owner or operator shall meet the requirements of 40 CFR § 63.764(d)(2).
 - (v) If an alternate circulation rate is required, the determination must be submitted in accordance with 40 CFR § 63.764(d)(2)(ii).

2. Recordkeeping Requirements

For each glycol dehydration unit, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

- (a) The location of the glycol dehydration unit;

- (b) The calculation for the optimum glycol circulation rate or the alternative glycol circulation rate in accordance with 40 CFR § 63.775(c)(7), if applicable;
- (c) The determination of the actual average benzene or BTEX emissions in accordance with 40 CFR § 63.774(d)(1), if applicable;
- (d) The emissions calculations for each glycol dehydrator in accordance with 25 Pa. Code § 135.5; **and**
- (e) Records of deviations and malfunctions in accordance with 40 CFR § 63.774(g), if applicable.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each glycol dehydration unit operated during the reporting period shall include:

- (a) The records of the optimum or alternative glycol circulation rate in accordance with 40 CFR § 63.775(c)(7), if applicable; **and**
- (b) The records of any deviations and malfunctions in accordance with 40 CFR § 63.775(c)(6), if applicable.

The emissions from each glycol dehydration unit operated during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION C. STATIONARY NATURAL GAS-FIRED SPARK IGNITION INTERNAL COMBUSTION ENGINES

1. BAT Compliance Requirements

- (a) For each natural gas-fired spark ignition internal combustion engine constructed under and authorized to operate under GP-5 approved by the Department on or after March 10, 1997 but prior to February 2, 2013, the owner or operator shall:
 - (i) Operate or equip the engine with air cleaning devices to meet the following emission levels:
 - (A) NO_x (as NO₂) of 2.0 g/bhp-h while operating at rated bhp and speed;
 - (B) Non-Methane Non-Ethane Hydrocarbon (NMNEHC), as propane, excluding formaldehyde, of 2.0 g/bhp-h while operating at rated bhp and speed; **and**
 - (C) CO of 2.0 g/bhp-h while operating at rated bhp and speed.
 - (ii) Ensure that at operating conditions less than rated capacity, the engine shall on a lb/h basis emit no more than it would emit at rated bhp and speed.
 - (iii) Ensure the engine meets the applicable requirements of (d) below.

- (b) For each natural gas-fired spark ignition internal combustion engine constructed and authorized to operate under GP-5 approved by the Department on or after February 2, 2013, but prior to August 8, 2018, the owner or operator shall:

- (i) Ensure the engine does not exceed the emissions standards specified in the following table:

Engine Type	Rated bhp	NO _x	CO	NMNEHC (as propane) excluding HCHO	HCHO
Lean-Burn	≤100	2.0 g/bhp-h	2.0 g/bhp-h	-	-
Lean-Burn	>100 - ≤500	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	-
Lean-Burn	>500	0.50 g/bhp-h	47 ppmvd @ 15% O ₂ <u>or</u> 93% reduction	0.25 g/bhp-h	0.05 g/bhp-h
Rich-Burn	≤100	2.0 g/bhp-h	2.0 g/bhp-h	-	-
Rich-Burn	>100 - ≤500	0.25 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	-
Rich-Burn	>500	0.20 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	2.7 ppmvd @ 15% O ₂ <u>or</u> 76% reduction

- (ii) Ensure the engine meets the applicable requirements of (d) below.

- (c) For each natural gas-fired spark ignition internal combustion engine constructed and authorized to operate on or after August 8, 2018, the owner or operator shall:

- (i) Ensure the engine does not exceed the emission standards specified in the following table:

Engine Type	Rated bhp	NO _x	CO	NMNEHC (as propane) excluding HCHO	HCHO
Lean-Burn	<100	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	-
Lean-Burn	≥100 - ≤500	1.0 g/bhp-h	0.70 g/bhp-h	0.30 g/bhp-h	-
Lean-Burn	>500 - <2,370	0.50 g/bhp-h	0.25 g/bhp-h	0.25 g/bhp-h	0.05 g/bhp-h
Lean-Burn	≥2,370	0.30 g/bhp-h Uncontrolled <u>or</u> 0.05 g/bhp-h with Control	0.25 g/bhp-h	0.25 g/bhp-h	0.05 g/bhp-h
Rich-Burn	<100	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	-
Rich-Burn	≥100 - ≤500	0.25 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	-
Rich-Burn	>500	0.20 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	2.7 ppmvd @ 15% O ₂ <u>or</u> 76% reduction

- (ii) Ensure that for engines that control NO_x emissions with a control technology that uses ammonia or urea as a reagent, the exhaust ammonia slip is limited to 10 ppmvd or less corrected to 15% O₂.

- (iii) Ensure the engine meets the applicable requirements of (d) below.
- (d) The owner or operator of the engine shall also:
 - (i) Comply with the applicable requirements of 40 CFR Part 63, Subpart ZZZZ for engines constructed (as defined in Subpart ZZZZ) prior to June 12, 2006;
 - (ii) Ensure the engine meets the visible emissions standards, as determined by the methods described in 25 Pa. Code § 123.43, by not exceeding the following limitations:
 - (A) Equal to or greater than 10% for a period or periods aggregating more than three minutes in any one hour; **and**
 - (B) Equal to or greater than 30% at any time
 - (iii) Install, operate, and maintain a non-resettable hour meter;
 - (iv) Limit the engine's time spent at idle during startup or shutdown to a period appropriate for the operation of the engine and air pollution control equipment consistent with good air pollution control practices, not to exceed 30 minutes, during which time the emissions standards in (b) through (d) do not apply.
 - (v) Conduct performance tests and periodic monitoring for the engine as detailed in Conditions 4 and 5 of this section on the following schedule:

Engine Size hp	Initial Compliance Performance Test	Continuous Compliance Performance Test	Periodic Monitoring
<100	None Required	None Required	Every 2,500 hours of operation
≥100 - ≤500	Within 180 days of startup of the engine	Within 180 days of each reauthorization	Every 2,500 hours of operation
>500 and not subject (d)(i)	Within 180 days of startup of the engine	Every 8,760 hours of operation or every three years and within 180 days of each reauthorization	Every 2,500 hours of operation
>500 and subject to (d)(i)	Not Applicable	Every year	Every 2,500 hours of operation

- (A) For an engine greater than or equal to 100 hp and less than or equal to 500 hp, if the engine is certified by the manufacturer in accordance with 40 CFR Part 60, Subpart JJJJ and the owner or operator operates and maintains the engine in accordance with the manufacturer's instructions, the performance testing requirements are waived.
- (B) For an engine greater than 500 hp, if the engine is certified by the manufacturer in accordance with 40 CFR Part 60, Subpart JJJJ and the owner or operator operates and maintains the engine in accordance with the manufacturer's instructions, the continuous compliance performance testing requirements every 8,760 hours of operation or every three years are waived.
- (C) The Department may alter the frequency of periodic monitoring based on the test results. The frequency of periodic monitoring may be altered upon request of the owner or operator with written Departmental approval.

2. Recordkeeping Requirements

For each engine, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

- (a) The GP-5 authorization number and the date each engine was authorized for use;
- (b) The make, model, and serial number of each engine;
- (c) Either a copy of the manufacturer's maintenance instructions **or** an alternative maintenance plan;
- (d) Records of maintenance conducted on each engine and any installed air pollution control devices;
- (e) A copy of the manufacturer's engine certification or vendor guarantees;

- (f) The results of each periodic monitoring;
- (g) The summary for each complete test report described in Section A Condition 14(i); **and**
- (h) The emissions calculations for each engine in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

The emissions from each natural gas-fired spark ignition internal combustion engine operated during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

4. Engine Performance Testing Requirements

- (a) When conducting a performance test for an engine, the owner or operator must submit the test protocol described in Section A. Condition 14(f) for review and approval.
- (b) The owner or operator should conduct the following test procedures:
 - (i) Conduct three test runs of at least one hour duration within 10% of 100% peak (or the highest achievable) load.
 - (ii) Select the sampling port location and the number and location of traverse points at the exhaust using 40 CFR Part 60, Appendix A-1, Method 1 or 1A depending on stack diameter, or the sampling points selected according to 40 CFR Part 60, Appendix A-4, Method 7E Section 8.1.2.
 - (iii) Determine the effluent characteristics by either:
 - (A) Calculating the exhaust flow in accordance with 40 CFR Part 60, Appendix A-7, Method 19 and measuring the O₂ concentration using 40 CFR Part 60, Appendix A-2, Method 3A; **or**
 - (B) By measuring:
 - (1) The flow velocity, stack temperature, static pressure, and barometric pressure using 40 CFR Part 60, Appendix A-1, Method 2 or 2C depending on stack diameter;
 - (2) The gas density using 40 CFR Part 60, Appendix A-2, Method 3A; **and**
 - (3) The moisture content using 40 CFR Part 60, Appendix A-3, Method 4.
 - (iv) Simultaneous to the determination of the O₂ concentration in (iii)(A) or (B) above, determine:
 - (A) The NO_x concentration of the exhaust gas using 40 CFR Part 60, Appendix A-4, Method 7E;
 - (B) The CO concentration of the exhaust gas using 40 CFR Part 60, Appendix A-4, Method 10;
 - (C) The NMNEHC concentration, as propane, excluding formaldehyde of the exhaust gas using ALT-106; **and**
 - (D) The formaldehyde concentration of the exhaust gas, **if applicable**, using 40 CFR Part 63, Appendix A, Method 320.
- (c) If at any time the owner or operator operates the engine in excess of the highest achievable load plus 10%, the owner or operator must perform a stack test within 180 days from the anomalous operation.

5. Engine Periodic Monitoring Requirements

- (a) When conducting periodic monitoring on an engine, the owner or operator may follow the procedures in (b) below. If the owner or operator decides to deviate from those procedures, they must submit a request to use an alternate procedure, in writing, at least 60 days prior to performing the periodic monitoring. In the alternate procedure request, the owner or operator must demonstrate the alternate procedure's equivalence to the standard procedure to the satisfaction of the Division of Source Testing and Monitoring.
- (b) *Standardized Periodic Monitoring Procedure.*
 - (i) Conduct three test runs of at least 20 minutes duration within 10% of 100% peak (or the highest achievable) load.
 - (ii) Determine NO_x and CO emissions and O₂ concentrations in the exhaust with either an electro-chemical cell portable gas analyzer used and maintained in accordance with the manufacturer's specifications and

following the procedures specified in the current version of ASTM D6522 or by following the procedures in 4(b) (ii) – (iv) (A) and (B) of this section.

- (iii) If the measured NO_x or CO emissions concentrations are in exceedance of the emissions limit, the owner or operator must perform a stack test in accordance with the Performance Testing Requirements of Condition 4 within 180 days of the periodic monitoring.
- (c) The 2,500 hours of operation count resets after any performance test performed in accordance with Condition 4 above.
- (d) For engines constructed (as defined in that subpart) prior to June 12, 2006, that installed a continuous parametric monitoring system (CPMS) to monitor the catalyst inlet temperature, the owner or operator must install, operate, and maintain the CPMS according to 40 CFR § 63.6625(b)(1) through (6).

SECTION D. RECIPROCATING COMPRESSORS

1. BAT Compliance Requirements

The owner or operator of a reciprocating compressor must meet the applicable requirements of 40 CFR § 60.5385 or 40 CFR § 60.5385a.

2. Recordkeeping Requirements

For each reciprocating compressor, the owner or operator shall maintain records in accordance with Section A Condition 12 and 40 CFR § 60.5420(c)(3) or § 60.5420a(c)(3) as applicable.

In addition, the emissions calculation for each reciprocating compressor must be kept in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each reciprocating compressor operated during the reporting period shall be submitted in accordance with 40 CFR § 60.5420(b)(4) or § 60.5420a(b)(4) as applicable.

The emissions from each reciprocating compressor operating during the reporting period must be included in the emissions inventory report of Section A Condition 13(d), including the emissions from scheduled and unscheduled blowdowns.

SECTION E. STORAGE VESSELS

1. BAT Compliance Requirements

- (a) For each storage vessel constructed and authorized to operate on or after August 23, 2011, but prior to August 8, 2018, the owner or operator shall meet the applicable requirements of 40 CFR §§ 60.5365(e) and 60.5395(d) and (e).
- (b) For each storage vessel constructed and authorized to operate on or after August 8, 2018, with a methane emission rate of 200 tpy or greater, a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, the owner or operator shall equip the storage vessel with a cover and route all vapor through a closed vent system to a control device that reduces methane, VOC, and HAP emissions by 95% or more by meeting the applicable control, cover, and closed vent system requirements of Section J Condition 1(a) through (f) or any alternative method approved by the Department.
- (c) Any storage vessel returned to service must meet the requirements of 40 CFR § 60.5395(f) or § 60.5395a(c).
- (d) Any storage vessel with a capacity greater than or equal to 2,000 gallons and less than or equal to 40,000 gallons must meet the requirements of 25 Pa. Code § 129.57.
- (e) Any storage vessel with a capacity greater than 40,000 gallons must meet the requirements of 25 Pa. Code § 129.56, if applicable.

2. Recordkeeping Requirements

For each storage vessel, the owner or operator shall maintain records in accordance with Section A Condition 12 and 40 CFR § 60.5420(c)(5) or § 60.5420a(c)(5) as applicable.

In addition, the emissions calculation for each storage vessel, which may be calculated using Department-approved methods such as direct measurement; modeling programs such as the most recent version of EPA TANKS, ProMax, and API E&P Tanks; process simulation software such as HYSIM, HYSIS, WINSIM, and PROSIM; or calculation methodologies such as the Vazquez-Beggs equation, must be kept in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each storage vessel operated during the reporting period shall be submitted in accordance with 40 CFR § 60.5420(b)(6) or § 60.5420a(b)(6) as applicable. The emissions from each storage vessel operating during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION F. TANKER TRUCK LOAD-OUT OPERATIONS

1. BAT Compliance Requirements

(a) For all truck load-out operations that service a storage vessel with a methane emission rate of 200 tpy or greater, a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, where the loading rack was constructed and authorized to operate on or after August 8, 2018, the owner or operator shall:

- (i) Use a vapor balancing system when removing liquids from the storage vessel; and
- (ii) Ensure that each tanker truck that is used to remove liquids from the storage vessel has passed one of the following annual leak tests:
 - (A) A tanker truck that does not indicate more than 1" H₂O pressure change within 5 minutes after being pressurized to 18" H₂O and after being depressurized to 6" H₂O vacuum has passed a MACT-level test and is assumed to have a collection efficiency of 99.2%.
 - (B) A tanker truck that does not indicate more than 3" H₂O pressure change within 5 minutes after being pressurized to 18" H₂O and after being depressurized to 6" H₂O vacuum has passed an NSPS-level test and is assumed to have a collection efficiency of 98.7%.
 - (C) A tanker truck that has passed a leak test performed in accordance with 49 CFR § 180.407 is accepted as equivalent to an NSPS-level collection efficiency of 98.7%.
 - (D) A tanker truck that has passed a leak test performed in accordance with 40 CFR Part 60, Appendix A-8, Method 27 is accepted as equivalent to an NSPS-level collection efficiency of 98.7%.
- (iii) As an alternative to (i) and (ii), VOC emissions must be controlled with 95% or greater efficiency.

2. Recordkeeping Requirements

For each tanker truck load-out operation, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

- (a) The identification, location, and date of construction of each vapor recovery load-out system;
- (b) Records of each tanker truck load-out operation including the date and time of the liquids load-out, the type and volume of liquids loaded, and the truck collection efficiency based on the annual leak test; and
- (c) The emissions calculation for each tanker truck load-out operation in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

The emissions from tanker truck load-out operations during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION G. FUGITIVE EMISSIONS COMPONENTS

1. BAT Compliance Requirements

- (a) For each fugitive emissions component constructed and authorized to operate under GP-5 approved by the Department on or after February 2, 2013, but prior to August 8, 2018, the following applies:
- (i) The owner or operator of the natural gas compression and/or processing facility shall, at a minimum, on a monthly basis perform a leak detection and repair program that includes audible, visual, and olfactory (AVO) inspections.
 - (ii) Within 180 days after the initial startup of a source, the owner or operator of the facility shall at a minimum, on a quarterly basis, use forward looking infrared (FLIR) cameras or other leak detection monitoring devices approved by the Department for the detection of fugitive leaks. The Department may grant an extension for use of FLIR camera upon receipt of a written request from the owner or operator of the facility documenting the justification for the requested extension.
 - (iii) If any leak is detected, the owner or operator of the facility shall repair the leak as expeditiously as practicable, but no later than fifteen (15) calendar days after the leak is detected, except as provided in 40 CFR §§ 60.482-60.489. The owner or operator shall record each leak detected and the associated repair activity. The records shall be retained for a minimum of five (5) years and shall be made available to the Department upon request.
- (b) For each fugitive emissions component constructed and authorized to operate on or after August 8, 2018, the following applies:
- (i) No later than 30 days after an emission source commences operation, and at least monthly thereafter, the owner or operator of a facility shall conduct an AVO inspection.
 - (ii) No later than 60 days after initial startup, and quarterly thereafter, the owner or operator shall conduct an LDAR program using either an OGI camera, a gas leak detector that meets the requirements of 40 CFR Part 60, Appendix A-7, Method 21, or other leak detection methods approved by the Division of Source Testing and Monitoring.
 - (A) The owner or operator may request, in writing, an extension of the LDAR inspection interval from the Air Program Manager of the appropriate DEP Regional Office.
 - (B) Any fugitive emissions components that are difficult-to-monitor or unsafe-to-monitor must be identified in the monitoring plan described in Condition 2(a) below.
 - (iii) The detection devices must be operated and maintained in accordance with manufacturer-recommended procedures, as required by the test method, or a Department-approved method.
 - (iv) A leak is defined as:
 - (A) Any positive indication, whether audible, visual, or odorous, determined during an AVO inspection;
 - (B) Any visible emissions detected by an OGI camera calibrated according to 40 CFR § 60.18 and a detection sensitivity level of 60 grams/hour; or
 - (C) A concentration of 500 ppm calibrated as methane or greater detected by an instrument reading.
 - (v) For quarterly inspections using a gas leak detector in accordance with 40 CFR Part 60, Appendix A-7, Method 21, the owner or operator may choose to adjust the detection instrument readings to account for the background organic concentration level as determined according to the procedures in Section 8.3.2.
 - (vi) Any leak detected from a fugitive emission component shall be repaired by the owner or operator of the facility as expeditiously as practicable. A first attempt at repair must be attempted within 5 calendar days of detection, and repair must be completed no later than 15 calendar days after the leak is detected unless:
 - (A) The owner or operator must purchase parts, in which case the repair must be completed no later than 10 calendar days after the receipt of the purchased parts; or
 - (B) The repair or replacement is technically infeasible, would require a vent blowdown, a compressor station, processing plant or transmission station shutdown, or would be unsafe to repair during operation of the unit, in which case the repair or replacement must be completed during the next

scheduled compressor station, processing plant or transmission station shutdown, after a planned vent blowdown or within 2 years, whichever is earlier.

- (vii) Once a fugitive emission component has been repaired or replaced, the owner or operator must resurvey the component as soon as practicable, but no later than 30 calendar days after the leak is repaired.
 - (A) For repairs that cannot be made during the monitoring survey when the leak is initially found, either a digital photograph must be taken of the component or the component must be tagged for identification purposes.
 - (B) A leak is considered repaired if:
 - (1) There are no detectable emissions consistent with Section 8.3.2 of 40 CFR Part 60, Appendix A-7, Method 21;
 - (2) A leak concentration of less than 500 ppm as methane is detected when the gas leak detector probe inlet is placed at the surface of the component;
 - (3) There is no visible leak image when using an OGI camera calibrated at a detection sensitivity level of 60 grams/hour; or
 - (4) There is no bubbling at the leak interface using a soap solution bubble test specified in Section 8.3.3 of 40 CFR Part 60, Appendix A-7, Method 21.
- (c) The Department determined that the VOC and methane emissions remaining after the implementation of BAT requirements, including LDAR, are of minor significance with regard to causing air pollution, and will not, on their own, be preventing or interfering with the attainment or maintenance of an ambient air quality standard.

2. Recordkeeping Requirements

For fugitive emissions components, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

- (a) The fugitive emissions monitoring plan in accordance with 40 CFR § 60.5397a(b) through (d).
- (b) Records of each monitoring survey which must include:
 - (i) The facility name and location;
 - (ii) The GP-5 authorization number;
 - (iii) The date, start time, and end time of the survey;
 - (iv) The name of the operator(s) performing the survey;
 - (v) The monitoring instrument used;
 - (vi) The ambient temperature, sky conditions, and maximum wind speed at the time of the survey;
 - (vii) Any deviations from the monitoring plan or a statement that there were none; **and**
 - (viii) Documentation of each fugitive emission including:
 - (A) The identification of each component from which fugitive emissions were detected;
 - (B) The instrument reading of each fugitive emissions component that meets the leak definition in Condition 1(b)(iv)(C) of this section;
 - (C) The status of repair of each component including:
 - (1) The repair methods applied in each attempt to repair the component;
 - (2) The tagging or digital photographing of each component not repaired during the monitoring survey in which the fugitive emissions were discovered;
 - (3) The reasons a component was placed on delay of repair;
 - (4) The date of successful repair of the component; **and**

- (5) The information on the instrumentation or method used to resurvey the component after repair, if it was not completed during the monitoring survey in which the fugitive emissions were discovered.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the records of each monitoring survey conducted during the reporting period shall be included.

The emissions from fugitive emissions components during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION H. NATURAL GAS-DRIVEN PNEUMATIC CONTROLLERS

1. BAT Compliance Requirements

- (a) For pneumatic controllers constructed and authorized to operate on or after August 23, 2011, the owner or operator must meet the applicable requirements of 40 CFR § 60.5390(a) and (b)(1) or (c)(1) or § 60.5390a(a) and (b)(1) or (c)(1).
- (b) Each controller must be tagged in accordance with 40 CFR § 60.5390(b)(2) and (c)(2) or § 60.5390a(b)(2) and (c)(2) as applicable.

2. Recordkeeping Requirements

For each controller, the owner or operator shall maintain records in accordance with Section A Condition 12 and 40 CFR § 60.5420(c)(4) or § 60.5420a(c)(4) as applicable.

In addition, the emissions calculation for each pneumatic controller must be kept in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each controller during the reporting period shall be done in accordance with 40 CFR § 60.5420(b)(5) or § 60.5420a(b)(5) as applicable.

The emissions from each pneumatic controller during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION I. NATURAL GAS-DRIVEN PNEUMATIC PUMPS

1. BAT Compliance Requirements

- (a) For each natural gas-driven pneumatic diaphragm pump constructed and authorized to operate on or after September 18, 2015, but prior to August 8, 2018, the owner and operator shall meet the applicable requirements of 40 CFR § 60.5365a(h)(1) and § 60.5393a(a) and (c) through (e).
- (b) For each natural gas-driven pneumatic pump constructed and authorized to operate on or after August 8, 2018, the owner or operator of a pump with:
 - (i) A methane emission rate of less than 200 tpy, a VOC emission rate of less than 2.7 tpy, a single HAP emission rate less than 0.5 tpy, and a total HAP emission rate less than 1.0 tpy, shall meet the applicable requirements of 40 CFR § 60.5365a(h)(1) and § 60.5393a(a) and (c) through (e).
 - (ii) A methane emission rate of 200 tpy or greater, a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, shall route all vapor through a closed vent system to a control device that reduces methane, VOC, and HAP emissions by 95% or more by meeting the applicable requirements of Section J.

2. Recordkeeping Requirements

For each natural gas-driven pneumatic diaphragm pump, the owner or operator shall maintain the following records in accordance with Section A Condition 12:

- (a) The location, date of installation, and manufacturer's specifications for each pump.
- (b) The emissions calculation for each pneumatic pump must be kept in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

The emissions from each natural gas-driven pneumatic diaphragm pump during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION J. ENCLOSED FLARES AND OTHER EMISSION CONTROL DEVICES

1. BAT Compliance Requirements

(a) *Enclosed Flares and Other Enclosed Combustion Control Devices.*

- (i) The owner or operator of an enclosed flare or other enclosed combustion control device shall meet the requirements of 40 CFR § 60.5412(d)(1) and § 60.5415(e) or 40 CFR § 60.5412a(d)(1) and § 60.5415a(e) as applicable. The Department may allow open flares at remote locations and for infrequent operations, provided the flare is installed and operated consistent with 40 CFR § 60.18.
- (ii) The owner or operator must conduct a performance test in accordance with Condition 4 within 180 days of initial startup of the affected facility unless:
 - (A) The combustion control device is a manufacturer-tested model tested in accordance with 40 CFR § 60.5413(d) or § 60.6413a(d); or
 - (B) A performance test conducted on a device of the same make and model in similar service at another facility within the Commonwealth approved by the Department may be used to satisfy this requirement.
- (iii) The owner or operator must conduct performance tests in accordance with Condition 4 within 180 days of each reauthorization unless:
 - (A) The combustion control device is a manufacturer-tested model tested in accordance with 40 CFR § 60.5413(d) or § 60.5413a(d);
 - (B) A performance test conducted on a device of the same make and model in similar service at another facility within the Commonwealth approved by the Department may be used to satisfy this requirement;
 - (C) The Department uses EPA's National Stack Testing Guidance for stack test waivers. or
 - (D) The combustion control device established a correlation between the outlet TOC performance level and the firebox or combustion chamber temperature during the initial performance test.
- (iv) The owner or operator of any combustion control device that is a manufacturer tested model shall meet the requirements of 40 CFR § 60.5413(e) or § 60.5413a(e) as applicable.

(b) *Vapor Recovery Devices.*

- (i) The owner or operator of a vapor recovery device constructed prior to August 8, 2018, shall meet the requirements of 40 CFR § 60.5412(d)(2) and § 60.5415(e) or 40 CFR § 60.5412a(d)(2) and § 60.5415a(e) as applicable.
- (ii) The owner or operator shall conduct a performance test in accordance with Condition 4 and 40 CFR § 60.5413(b)(5) or § 60.5413a(b)(5) as applicable.
- (iii) The owner or operator of any vapor recovery device shall conduct a monthly AVO inspection in accordance with 40 CFR § 60.5417(h)(2) or § 60.5417a(h)(2) as applicable.
- (iv) If the vapor recovery device is a carbon adsorption unit, the owner or operator shall meet the requirements of 40 CFR § 60.5412(c) or § 60.5412a(c) as applicable.

(c) *External Floating Roof.*

- (i) An external floating roof shall meet the requirements of 40 CFR § 60.112b(a)(2) and 25 Pa. Code § 129.56(b) as applicable.
- (ii) Perform a gap measurement test in accordance with 40 CFR § 60.113b for mechanical shoe or liquid-mounted primary seals.

- (iii) Perform a gap measurement test in accordance with 25 Pa. Code § 129.56(b)(iii) for a vapor-mounted primary seal.
- (d) *Internal Floating Roof.*
 - (i) An internal floating roof shall meet the requirements of 40 CFR § 60.112b(a)(1) and 25 Pa. Code § 129.56(c) as applicable.
 - (ii) Visually inspect the internal floating roof, primary seal, and secondary seal (if equipped) in accordance with 40 CFR § 60.113b(a).
- (e) *Covers.*
 - (i) The cover and all openings on the cover shall meet the requirements of 40 CFR § 60.5411(b) and § 60.5416(a)(3) or 40 CFR § 60.5411a(b) and § 60.5416a(a)(3) as applicable.
 - (ii) The owner or operator shall conduct AVO inspections for defects that could result in air emissions in accordance with Section G Condition 1(b)(i). Defects include, but are not limited to, visible cracks, holes, or gaps in the cover or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices.
 - (iii) Any defect or leak detected shall be repaired in accordance with Section G Condition 1(b)(vi) and (vii).
- (f) *Closed Vent Systems.*
 - (i) The owner or operator shall conduct an assessment in accordance with 40 CFR § 60.5411a(d), **if applicable.**
 - (ii) The owner or operator shall design and operate the closed vent system with no detectable emissions, as determined in accordance with 40 CFR § 60.5411(a) and (c) and § 60.5416(a) through (c) or 40 CFR § 60.5411a(a) and (c) and § 60.5416a(a) through (c) as applicable.
 - (iii) The owner or operator shall conduct AVO inspections for defects that could result in air emissions in accordance with Section G Condition 1(b)(i). Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; and broken or missing caps or other closure devices.
 - (iv) Any defect or leak detected shall be repaired in accordance with Section G Condition 1(b)(vi) and (vii).

2. Recordkeeping Requirements

For each control device, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including:

- (a) *Enclosed Flares and Other Enclosed Combustion Control Devices.*
 - (i) For non-manufacturer-tested models, the owner or operator must maintain records in accordance with 40 CFR § 60.5420(c)(13) and (14) or § 60.5420a(c)(13) and (14) as applicable.
 - (ii) For manufacturer-tested models, the owner or operator must maintain records in accordance with 40 CFR § 60.5413(d)(12) and (e) or § 60.5413a(d)(12) and (e) as applicable.
 - (iii) The summary for each complete test report described in Section A Condition 14(i) conducted, **if applicable.**
- (b) *Vapor Recovery Devices.*
 - (i) The owner or operator must maintain records in accordance with 40 CFR § 60.5420(c)(12) through (14) or § 60.5420a(c)(12) through (14) as applicable.
 - (ii) The design analysis in accordance with 40 CFR § 60.5413(c) or § 60.5413a(c), as applicable.
 - (iii) The summary for each complete test report described in Section A Condition 14(i) conducted, **if applicable.**

(c) *External Floating Roof.*

- (i) The owner or operator must maintain records in accordance with 40 CFR §§ 60.115b and 60.116b as applicable; and
- (ii) The owner or operator must maintain records in accordance with 25 Pa. Code § 129.56(f)(3) and (g), **if applicable.**

(d) *Internal Floating Roof.*

- (i) The owner or operator must maintain records in accordance with 40 CFR §§ 60.115b and 60.116b as applicable; and
- (ii) The owner or operator must maintain records in accordance with 25 Pa. Code § 129.56(f)(3) and (g), **if applicable.**

(e) *Covers.*

- (i) The owner or operator must maintain records in accordance with Section G Condition 2(b).

(f) *Closed Vent Systems.*

- (i) The owner or operator must maintain records in accordance with Section G Condition 2(b).
- (ii) The owner or operator must maintain records in accordance with 40 CFR § 60.5420(c)(8) and (9).
- (iii) The owner or operator must maintain records of the assessment, including the engineer's certification, in accordance with 40 CFR § 60.5420a(c)(17), **if applicable.**

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each control device in operation during the reporting period shall be done in accordance with 40 CFR § 60.5420(b) or § 60.5420a(b) as applicable.

4. Control Device Performance Testing Requirements

When conducting a performance test, the owner or operator must submit the test protocol described in Section A. Condition 14 (f) for review and approval. The owner or operator should conduct the following test procedures:

- (a) Conduct three test runs of at least one-hour duration while operating the control device within 5% of the required operating temperature.
- (b) Select the sampling port location and the number and location of traverse points at the exhaust using 40 CFR Part 60, Appendix A-1, Method 1 or 1A depending on stack diameter.
 - (i) If demonstrating compliance with a percent reduction requirement, sampling sites must be located at the inlet of the first control device and the outlet of the final control device; **or**
 - (ii) If demonstrating compliance with an outlet concentration requirement, the sampling site must be located at the outlet of the control device.
- (c) Determine the effluent characteristics including:
 - (i) The flow velocity, stack temperature, static pressure, and barometric pressure using 40 CFR Part 60, Appendix A-1, Method 2 or 2C depending on stack diameter;
 - (ii) The gas density using 40 CFR Part 60, Appendix A-2, Method 3A; **and**
 - (iii) The moisture content using 40 CFR Part 60, Appendix A-3, Method 4.
- (d) To demonstrate compliance with (b)(i), use 40 CFR Part 60, Appendix A-7, Method 25A to determine the Total Organic Compounds (TOC) and then convert to dry basis using the moisture content from (c)(iii) above and calculate the inlet and outlet mass rates as propane and the percent reduction.
- (e) To demonstrate compliance with (b)(ii), use 40 CFR Part 60, Appendix A-7, Method 25A to determine the TOC and 40 CFR Part 60, Appendix A-6, Method 18 to determine the methane and ethane concentration, and then correct the TOC concentration, minus methane and ethane, for percent oxygen from (c)(ii) above.

5. Control Device Periodic Monitoring Requirements

The owner or operator that installs a CPMS must install, operate, and maintain the CPMS according to 40 CFR § 60.5415 and § 60.5417 or 40 CFR § 60.5415a and § 60.5417a as applicable.

SECTION K. PIGGING OPERATIONS

1. BAT Compliance Requirements

- (a) The owner or operator that conducts pigging operations shall employ best management practices to minimize the liquids present in the pig receiver chamber and to minimize emissions from the pig receiver chamber including, but not limited to, installing liquids ramps, installing liquids drain, routing high-pressure chambers to a low-pressure line or vessel, using ball valve type chambers, or using multiple pig chambers. The selection of the appropriate best management practices must be documented in the application.
- (b) For pigging operations with a methane emission rate of 200 tpy or greater, or a VOC emission rate of 2.7 tpy or greater, or a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, after employing best management practices, the owner or operator shall control methane, VOC, and HAP emissions from all pigging operations by at least 95% with a condenser, flare, thermal oxidizer, vapor recovery unit, or other air cleaning device, or any alternative method approved by the Department that meets the applicable requirements in Section J.

2. Recordkeeping Requirements

For each pigging operation, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

- (a) The identification, location, and date of construction of each pig launcher or receiver;
- (b) Records of each pigging operation including the identification of the pig chamber used, the date and time of the pigging operation, and the type and volume of liquids cleared; and
- (c) The emissions calculation for each pig chamber, using the Department's spreadsheet found at <http://files.dep.state.pa.us/> or other equivalent method.

3. Reporting Requirements

The emissions from each pigging operation conducted during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION L. NATURAL GAS-FIRED COMBUSTION UNITS

1. BAT Compliance Requirements

- (a) Combustion units including, but not limited to, heated flash separator units, evaporator units, fractionation column heaters, and glycol dehydrator reboilers constructed and authorized to operate on or after August 8, 2018, shall have a rated heat input less than 50 MMBtu/h each and only be fired on natural gas.
- (b) For combustion units with a rated heat input of greater than or equal to 10 MMBtu/h, the owner or operator shall:
 - (i) Ensure that the emission limits in the following table are met:

Constructed or Modified After:	NO _x (ppmvd @ 3% O ₂)	CO (ppmvd @ 3% O ₂)	PM (lb/MMBtu)	Opacity (No more than 3 minutes in an hour)	Opacity (At any time)
December 2, 1995	30	300	0.4	20%	60%
August 8, 2018	30	130	0.4	10%	30%

- (ii) Conduct a performance test for NO_x and CO in accordance with Condition 4 below within 180 days of initial startup;
- (iii) Conduct either a performance test in accordance with Condition 4 below within 180 days of reauthorization of the GP-5 or conduct periodic monitoring in accordance with Condition 5 below;

- (iv) Ensure the combustion unit meets the visible emissions standards, as determined by the methods described in 25 Pa. Code § 123.43; and
- (v) Conduct, within 180 days of re-authorization of GP-5, a tune-up/inspection which at a minimum shall include:
 - (A) Inspecting the burner and cleaning or replacing any components of the burner as necessary;
 - (B) Inspecting the flame pattern and adjusting the burner as necessary to optimize the flame pattern consistent with the manufacturer's specifications or good combustion engineering practices;
 - (C) Inspecting the system air-to-fuel ratio controller and ensuring it is calibrated and functioning properly;
 - (D) Optimizing total emissions of CO consistent with the NO_x requirement and the manufacturer's specifications or good combustion engineering practices; **and**
 - (E) Measuring the concentrations in the effluent stream of CO in ppmv and O₂ in volume percent before and after adjustments are made in accordance with Condition 5 (b)(ii) below.
- (c) Integrated equipment, such as natural gas-driven pneumatic controllers (Section H), natural gas-driven pneumatic pumps (Section I), and any fugitive emissions components (Section G) are subject to the requirements of their respective Sections. Emissions from these sources are not required to be included in the uncontrolled emissions calculations for the combustion units in this section.

2. Recordkeeping Requirements

For each combustion unit, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

- (a) The location of the combustion unit;
- (b) Either the summary for each complete test report described in Section A Condition 14(i); **or** the results of each periodic monitoring;
- (c) The tune-up/inspection records, which shall at a minimum include:
 - (i) The date the tune-up/inspection was conducted;
 - (ii) The concentrations in the effluent stream of CO in ppmv and O₂ in volume percent as determined in Condition 5(b)(ii); and
 - (iii) A description of any corrective actions taken as part of the tune-up; **and**
- (d) The emissions calculations for the combustion unit in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

The emissions from each combustion unit operated during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

4. Combustion Unit Performance Testing Requirements

- (a) When conducting a performance test, the owner or operator must submit the test protocol described in Section A. Condition 14 (f) for review and approval.
- (b) The owner or operator should conduct the following test procedures.
 - (i) Conduct three test runs of at least one-hour duration within 10% of 100% peak (or the highest achievable) load.
 - (ii) Select the sampling port location and the number and location of traverse points at the exhaust using 40 CFR Part 60, Appendix A-1, Method 1 or 1A depending on stack diameter.
 - (iii) Determine the effluent characteristics including:
 - (A) The flow velocity, stack temperature, static pressure, and barometric pressure using 40 CFR Part 60, Appendix A-1, Method 2 or 2C depending on stack diameter;
 - (B) The gas density using 40 CFR Part 60, Appendix A-2, Method 3A; **and**

- (C) The moisture content using 40 CFR Part 60, Appendix A-3, Method 4.
- (iv) Simultaneous to the determination of the O₂ concentration in (iii)(B) above, determine:
 - (A) The NO_x concentration of the exhaust gas using 40 CFR Part 60, Appendix A-4, Method 7E; **and**
 - (B) The CO concentration of the exhaust gas using 40 CFR Part 60, Appendix A-4, Method 10.
- (c) If at any time the owner or operator operates the combustion unit in excess of the highest achievable load plus 10%, the owner or operator must perform a stack test within 180 days from the anomalous operation.

5. Combustion Unit Periodic Monitoring Requirements

- (a) When conducting periodic monitoring on a combustion unit, the owner or operator may follow the procedures in (b) below. If the owner or operator decides to deviate from those procedures, they must submit a request to use an alternate procedure, in writing, at least 60 days prior to performing the periodic monitoring. In the alternate procedure request, the owner or operator must demonstrate the alternate procedure's equivalence to the standard procedure to the satisfaction of the Division of Source Testing and Monitoring.
- (b) *Standardized Periodic Monitoring Procedure.*
 - (i) Conduct three test runs of at least 20-minutes duration within 10% of 100% peak (or the highest achievable) load.
 - (ii) Determine NO_x and CO emissions and O₂ concentrations in the exhaust with either an electro-chemical cell portable gas analyzer used and maintained in accordance with the manufacturer's specifications and following the procedures specified in the current version of ASTM D6522 or by following the procedures in 4(b) (ii) – (iv) of this section.
 - (iii) If the measured NO_x or CO emissions concentrations are in exceedance of the emissions limit, the owner or operator must perform a stack test within 180 days of the periodic monitoring.

SECTION M. STATIONARY NATURAL GAS-FIRED COMBUSTION TURBINES

1. BAT Compliance Requirements

- (a) For each natural gas-fired combustion turbine constructed and authorized to operate prior to February 1, 2013, the owner or operator shall abide by the terms and conditions of the applicable plan approval or operating permit under which they were authorized.
- (b) For each natural gas-fired combustion turbine constructed and authorized to operate under GP-5 approved by the Department on or after February 1, 2013, but prior to August 8, 2018, the owner or operator shall:
 - (i) Ensure the turbine does not exceed the emissions standards specified in the following table:

Turbine Rating (bhp)	NO _x (ppmvd @ 15% O ₂)	CO (ppmvd @ 15% O ₂)	NMNEHC (as propane) (ppmvd @ 15% O ₂)	Total PM (lb/MMBtu)
≥1,000 and <5,000	25	25	9	0.03
≥5,000 and <15,000	15	25	9	0.03
≥15,000	15	10 or 93% reduction	5 or 50% reduction	0.03

- (ii) Ensure the turbine meets the requirements of (d) below.

- (c) For each natural gas-fired combustion turbine constructed and authorized to operate on or after August 8, 2018, the owner or operator shall:

- (i) Ensure the turbine does not exceed the emission standards specified in the following table:

Turbine Rating (bhp)	NO_x (ppmvd @ 15% O₂)	CO (ppmvd @ 15% O₂)	NMNEHC (as propane) (ppmvd @ 15% O₂)	Total PM (lb/MMBtu, HHV)
≥1,000 and <5,000	25	25	9.0	0.03
≥5,000 and <15,900	15	10	5.0	0.03
≥15,900	9.0 Uncontrolled <u>or</u> 2.0 with Control	10 Uncontrolled <u>or</u> 1.8 with Control	5.0	0.03

- (ii) Ensure that, for turbines that control NO_x emissions with a control technology that uses ammonia or urea as a reagent, the exhaust ammonia slip is limited to 10 ppmvd or less corrected to 15% O₂.
- (iii) Demonstrate that the vendor's guarantee assures compliance with the total PM emission limits.
- (iv) Ensure the turbine meets the requirements of (d) below.
- (d) The owner or operator of the turbine shall also:
- (i) Ensure the turbine meets the visible emissions standards, as determined by the methods described in 25 Pa. Code § 123.43, by not exceeding the following limitations:
- (A) Equal to or greater than 10% for a period or periods aggregating more than three minutes in any one hour; **and**
- (B) Equal to or greater than 30% at any time.
- (ii) Install, operate, and maintain a non-resettable hour meter.
- (iii) Limit the turbine's time spent at idle during startup or shutdown to a period appropriate for the operation of the turbine and air pollution control equipment consistent with good air pollution control practices, not to exceed 30 minutes, during which time the emissions standards in (a) through (c) do not apply.
- (iv) Operate the turbine and air pollution control equipment consistent with good air pollution control practices during periods of low ambient air temperature (at or below 0 °F), during which time the emissions standards in (a) through (c) do not apply.
- (v) Conduct performance tests for the turbine as detailed in Condition 4 below within 180 days of initial startup and within 180 days of reauthorization of this General Permit and periodic monitoring for the turbine every 2,500 hours of operation. The Department may alter the frequency of periodic monitoring based on the test results. The frequency of periodic monitoring may be altered upon request of the owner or operator with written Departmental approval.

2. Recordkeeping Requirements

For each turbine, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

- (a) The location of each turbine;
- (b) The GP-5 authorization number and the date each turbine was authorized for use;
- (c) The make, model, and serial number of each turbine;
- (d) A copy of the manufacturer's maintenance instructions **or** an alternative maintenance plan;
- (e) Records of maintenance conducted on each turbine and any installed air pollution control devices;

- (f) A copy of the vendor's emission guarantees;
- (g) The results of each periodic monitoring;
- (h) The summary for each complete test report described in Section A Condition 14(i);
- (i) Representative fuel sampling data in accordance with 40 CFR § 60.4365(b);
- (j) The results of all compliance calculations in accordance with 40 CFR § 60.7(f), **if applicable; and**
- (k) The emissions calculations for each turbine in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

The emissions from each natural gas-fired combustion turbine operated during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

4. Turbine Performance Testing Requirements

- (a) When conducting a performance test, the owner or operator must submit the test protocol described in Section A. Condition 14 (f) for review and approval.
- (b) The owner or operator should conduct the following test procedures:
 - (i) Conduct three test runs of at least one hour duration within plus or minus 25% of 100% of peak load or at the highest achievable load point.
 - (ii) Select the sampling port location and the number and location of traverse points at the exhaust using 40 CFR Part 60, Appendix A-1, Method 1 or 1A depending on stack diameter, or the sampling points selected in accordance with 40 CFR Part 60, Appendix A-4, Method 7E, Section 8.1.2.
 - (iii) Determine the effluent characteristics by either:
 - (A) Calculating the exhaust flow in accordance with 40 CFR Part 60, Appendix A-7, Method 19 and measuring the O₂ concentration using 40 CFR Part 60, Appendix A-2, Method 3A; **or**
 - (B) By measuring:
 - (1) The flow velocity, stack temperature, static pressure, and barometric pressure using 40 CFR Part 60, Appendix A-1, Method 2 or 2C depending on stack diameter;
 - (2) The gas density using 40 CFR Part 60, Appendix A-2, Method 3A; **and**
 - (3) The moisture content using 40 CFR Part 60, Appendix A-3, Method 4.
 - (iv) Simultaneous to the determination of the O₂ concentration in (iii)(A) or (B) above, determine:
 - (A) The NO_x concentration of the exhaust gas using 40 CFR Part 60, Appendix A-4, Method 7E;
 - (B) The CO concentration of the exhaust gas using 40 CFR Part 60, Appendix A-4, Method 10; **and**
 - (C) The NMNEHC concentration, as propane, of the exhaust gas using ALT-106.
- (c) If at any time the owner or operator operates the turbine in excess of the highest achievable load plus 25%, the owner or operator must perform a stack test within 180 days from the anomalous operation.

5. Turbine Periodic Monitoring Requirements

- (a) When conducting periodic monitoring on a turbine, the owner or operator may follow the procedures in (b) below. If the owner or operator decides to deviate from those procedures, they must submit a request to use an alternate procedure, in writing, at least 60 days prior to performing the periodic monitoring. In the alternate procedure request, the owner or operator must demonstrate the alternate procedure's equivalence to the standard procedure to the satisfaction of the Division of Source Testing and Monitoring.
- (b) *Standardized Periodic Monitoring Procedure.*
 - (i) Conduct three test runs of at least 20 minutes duration within plus or minus 25% of 100% of peak load or at the highest achievable load point,

- (ii) Determine NO_x and CO emissions and O₂ concentrations in the exhaust with either an electro-chemical cell portable gas analyzer used and maintained in accordance with the manufacturer's specifications and following the procedures specified in the current version of ASTM D6522 or by following the procedures in 4(b) (ii) – (iv) (B) of this section.
 - (iii) If the measured NO_x or CO emissions concentrations are in exceedance of the emissions limit, the owner or operator must perform a stack test within 180 days of the periodic monitoring.
- (c) The 2,500 hours of operation count resets after any performance test performed in accordance with Condition 4 above.
- (d) For turbines that control NO_x emissions:
 - (i) Using water or steam injection, the owner or operator shall install, calibrate, maintain, and operate the appropriate continuous monitoring system in accordance with 40 CFR § 60.4335.
 - (ii) Using methods other than water or steam injection, the owner or operator shall install, calibrate, maintain, and operate the appropriate continuous monitoring system in accordance with 40 CFR § 60.4340(b).
 - (iii) The owner or operator that installs, calibrates, maintains, and operates a CPMS shall develop a site-specific parameter monitoring plan in accordance with 40 CFR § 60.4355.

6. Turbine Core Replacement Requirements

Turbine core replacement is allowed for a turbine, provided the following conditions are met:

- (a) The owner or operator shall provide thirty (30) days written notification to the Department of a planned turbine core replacement, or within seven (7) days after an unplanned replacement is commenced.
- (b) The written notice shall identify the location, the manufacturer, model, and serial number of the turbine, and the manufacturer, model, and serial number of the turbine core to be installed, or which has been installed, in the turbine and the air contaminant emission rates which will exist following the turbine core replacement, including NO_x, CO and NMNEHC.
- (c) The written notice shall also contain a certification from the owner or operator that any turbine core to be installed has been manufactured by either the existing turbine manufacturer or other manufacturer and will be a lower emitting turbine core or, if the core will be replaced with an identical core, that a lower emitting core is not available. Existing turbine manufacturers shall include companies that maintain the turbine cores of the existing turbines at the facility. If the permittee decides to install a turbine core obtained from a manufacturer other than the existing turbine manufacturer, the notice shall contain a certification, signed by a "responsible official" as defined in 25 Pa. Code Section § 121.1, that the permittee has examined the turbine cores that are available from all such manufacturers and will install, or has installed, the lowest emitting turbine core available from any manufacturer.
- (d) The core to be installed, or which has been installed, shall be an identical turbine core or lower emitting turbine core.
- (e) The notice shall be accompanied by a vendor-provided guarantee of the achievable air contaminant emission rates of the new turbine core. If such a guarantee is not available, the notice shall include certification that the permittee attempted to obtain such guarantee and an explanation as to why the vendor will not provide such a guarantee.
- (f) All certifications shall be signed by a responsible official and shall acknowledge that the certifying party is aware of the penalties for unsworn falsification to governmental authorities as established under 18 Pa.C.S. § 4904. The certification shall also state that based on information and belief formed after reasonable inquiry, that the information in the notice are true, accurate and complete.
- (g) For purposes of this General Permit, a turbine core is a "Lower Emitting Turbine Core" if it is commercially available, has the same operating characteristics as the core being removed and the rate of NO_x emissions, expressed as either parts per million by volume dry basis ("ppmvd") or pounds per hour ("lb/h") would be lower than the rates of emission achievable by any commercially available alternative turbine core when the respective turbine was operating at the same level of performance. If the horsepower, firing rate and operating speed of the core being removed falls within the ranges of horsepower, firing rate, and operating speed for the Lower Emitting Turbine Core, the Lower Emitting Turbine Core is considered to have the same operating characteristics as the

core being removed. A turbine core is an "Identical Turbine Core" if the rate of NO_x emissions is no higher than the emission rates of the turbine core being replaced when the respective turbine is operating at the same level of performance.

- (h) After a turbine core has been replaced, the permittee shall perform NO_x, CO, and NMNEHC emissions testing for the respective turbine compressor engine(s) within one-hundred twenty (120) days of completing the replacement. Stack testing shall be performed in accordance with Condition 4 of this Section.

SECTION N. CENTRIFUGAL COMPRESSORS

1. BAT Compliance Requirements

For a centrifugal compressor constructed and authorized to operate on or after August 23, 2011, the owner or operator shall meet the requirements of 40 CFR § 60.5380 or § 60.5380a as applicable.

2. Recordkeeping Requirements

For each centrifugal compressor, the owner or operator shall maintain the following records in accordance with Section A Condition 12 and 40 CFR § 60.5420(c)(2) or § 60.5420a(c)(2) as applicable.

In addition, the emissions calculation for each centrifugal compressor must be kept in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each centrifugal compressor operated during the reporting period shall be done in accordance with 40 CFR § 60.5420(b)(3) or § 60.5420a(b)(3) as applicable.

The emissions from each centrifugal compressor operating during the reporting period must be included in the emissions inventory report of Section A Condition 13(d), including the emissions from scheduled and unscheduled blowdowns.

Issued by: _____
Krishnan Ramamurthy
Director
Bureau of Air Quality

Date Issued: _____

Date Effective: _____

GENERAL PLAN APPROVAL AND/OR GENERAL OPERATING PERMIT BAQ-GPA/GP-5A

Unconventional Natural Gas Well Site Operations and Remote Pigging Stations

SECTION A. GENERAL REQUIREMENTS

1. Statutory/Regulatory Authority and General Description

In accordance with Section 6.1(f) of the Pennsylvania Air Pollution Control Act (APCA), 35 P.S. § 4006.1(f) and 25 Pa. Code Chapter 127, Subchapter H, the Department of Environmental Protection (Department or DEP) hereby issues this General Plan Approval and/or General Operating Permit (General Permit or GP-5A) for new or modified unconventional natural gas well site operations and remote pigging stations (facility or facilities) constructed, modified, or operated in this Commonwealth.

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3. Definitions

Words and terms that are not otherwise defined in this General Permit shall have the meanings set forth in Section 3 of the APCA (35 P.S. § 4003) and Title 25, Article III including 25 Pa. Code § 121.1 unless the context indicates otherwise. The meanings set forth in applicable definitions codified in the Code of Federal Regulations (CFR) including 40 CFR Part 60, Subparts JJJJ, OOOO, and OOOOa or 40 CFR Part 63, Subparts HH and ZZZZ shall also apply to this General Permit.

Fugitive Emissions Component – Any component that has the potential to emit fugitive emissions of methane, Volatile Organic Compounds (VOC), or Hazardous Air Pollutants (HAP) at an unconventional natural gas well site or remote pigging station including, but not limited to, valves, connectors, pressure relief devices, open-ended lines, flanges, compressors, instruments, meters, covers, and closed vent systems. Devices that vent as part of normal operations are not considered fugitive sources unless the emission originates from a place other than the vent.

Leak – A leak is defined as any release of gaseous hydrocarbons that is detected by Auditory, Visual, or Olfactory (AVO) inspection; an optical gas imaging (OGI) camera calibrated according to 40 CFR § 60.18 and a detection sensitivity level of 60 grams/hour; a gas leak detector that meets the requirements of 40 CFR Part 60, Appendix A-7, Method 21 that detects a concentration of 500 ppm calibrated as methane or greater; or other leak detection methods approved by the Department's Division of Source Testing and Monitoring. However, a release from any equipment or component designed by the manufacturer to protect the equipment, controller, or personnel or to prevent groundwater contamination, gas migration, or an emergency situation is not considered a leak.

Pigging Operations – The process of removing and collecting condensed liquids including condensate, intermediate hydrocarbons, or produced water, from a pipeline using a spherical or bullet-shaped device, known as a pig, forced through the pipeline by natural gas pressure. The liquids are then collected at their eventual destination in a storage tank, often referred to as a slug tank. This process also includes operation conducted for pipeline integrity evaluation.

Remote Pigging Station – A facility where pigging operations are conducted that is not located at an unconventional natural gas well site, natural gas compressor station, natural gas processing plant, or natural gas transmission station and which meets or exceeds the exemption criteria in Category 38(c) of the [Air Quality Permit Exemptions List](#).

Sour Gas – Natural gas where the Hydrogen Sulfide (H₂S) content is in excess of 4 ppmv at standard temperature and pressure.

Start of Production – The beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate, or produced water. A well whose owner or operator is selling gas through temporary equipment designed for flowback shall not be considered in production until either the sales continue through the temporary equipment for more than 30 days or the gas is routed to a permanent production separator.

Unconventional Natural Gas Well – A well drilled to produce natural gas from shale formations below the Elk Sandstone or its geologic equivalent stratigraphic interval, where recovery of the natural gas is generally not economic without the bores being stimulated by hydraulic fracturing, multilateral well bores, or other techniques to expose more of the formation to the well bore.

Unconventional Natural Gas Well Site – A location with one or more unconventional natural gas wells at which unconventional natural gas well site operations are conducted.

Unconventional Natural Gas Well Site Operations – Equipment and processes at unconventional natural gas well sites including, but not limited to, gas dehydration, tanker truck load-out, wellbore liquid unloading, gas compression, pigging, and storage.

Wellbore Liquids Unloading – The process of removing accumulated liquids from a natural gas well in order to restore well pressure and natural gas production.

4. Applicability/Scope

- (a) This General Permit authorizes the construction, modification, and/or operation of sources listed below at an unconventional natural gas well site or remote pigging station. The applicability of this General Permit may include one or more of the following operations or emissions sources:
- (i) Glycol Dehydration Units
 - (ii) Stationary Natural Gas-Fired Spark Ignition Internal Combustion Engines
 - (iii) Reciprocating Compressors
 - (iv) Storage Vessels
 - (v) Tanker Truck Load-Out Operations
 - (vi) Fugitive Emissions Components
 - (vii) Natural Gas-Driven Pneumatic Controllers
 - (viii) Natural Gas-Driven Pneumatic Pumps
 - (ix) Enclosed Flares and Other Emission Control Devices
 - (x) Pigging Operations
 - (xi) Wellbore Liquids Unloading Operations
- (b) An Application for Authorization to Use GP-5A may be submitted for the operation of an eligible source if the source is exempted from plan approval requirements under 25 Pa. Code § 127.14.
- (c) If any source located at the facility cannot be regulated under this General Permit, a plan approval and/or an operating permit issued in accordance with 25 Pa. Code, Chapter 127, Subchapter B and/or Subchapter F will be required.

5. Prohibited Use of GP-5A

GP-5A may not be used for the construction, modification, or operation of any of the following air contamination sources:

- (a) A proposed source located at a Title V facility including sources determined to be a single source Title V facility.

- (b) A proposed source that is subject to Title V permitting requirements specified in 25 Pa. Code Chapter 127, Subchapters F and G; prevention of significant deterioration requirements specified in 25 Pa. Code Chapter 127 Subchapter D; or nonattainment new source review requirements specified in 25 Pa. Code Chapter 127 Subchapter E.
- (c) A facility that produces or processes sour gas.
- (d) *Circumvention.*
 - (i) The owner or operator of a facility may not circumvent the new source review requirements of 25 Pa. Code Chapter 127, Subchapter E by causing or allowing a pattern of ownership or development, including the phasing, staging, delaying, or engaging in incremental construction over a geographic area of a facility which, except for the pattern of ownership or development, would otherwise require a permit or submission of a plan approval application.
 - (ii) No person may permit the use of a device, stack height that exceeds good engineering practice, dispersion technique, or other technique that without resulting in reduction of the total amount of air contaminants emitted, conceals or dilutes an emission of air contaminants that would otherwise be in violation of this General Permit, the APCA, or the regulations promulgated thereunder, except for those that are used for the control of malodors with the prior written approval of the Department.

6. Authorization to Use GP-5A

- (a) *Application for Authorization to Use GP-5A.* Pursuant to 25 Pa. Code § 127.621, any person proposing to construct, operate, or modify a source listed in Section A, Condition 4 of this General Permit at an unconventional natural gas well site or remote pigging station shall submit an Application for Authorization to Use GP-5A to the Air Program Manager of the appropriate DEP Regional Office responsible for authorizing the use of general permits in the county in which the facility will be located. This application shall be submitted to DEP either through the ePermitting system, by hand delivery, courier, or sent to DEP by certified mail, return receipt requested, in accordance with 25 Pa. Code § 127.621(b).
- (b) *Terms of Authorization to Use GP-5A.* This General Permit authorizes the construction and/or operation of the specific sources at the specific facility as described in the application for a term of five years from the date of authorization. The authorization to construct a source or facility will expire 18 months from the date of the authorization if the owner or operator fails to commence construction or if there is a lapse in construction of 18 months. The Department may extend the 18-month period upon an owner or operator providing satisfactory justification for an extension up to the original date of the five-year term. All requests for extension shall be submitted to the Department at least 30 days prior to the end of the 18-month period and are only valid upon receipt of written approval by the Department. The expiration of the authorization to construct will require a new Application for Authorization to Use GP-5A if an extension is not requested and granted.
- (c) *Expiration of and Re-Authorization to Use GP-5A.*
 - (i) The authorization granted by the Department to construct and/or operate under this General Permit shall terminate on the date of expiration unless a complete Application for Authorization to Use GP-5A is submitted to the Department at least 30 calendar days prior to the expiration date.
 - (ii) Upon receipt by the Department of a timely, administratively and technically complete application for re-authorization to operate under this General Permit, the owner or operator may continue to operate the facility subject to final action by the Department provided that the sources and the facility are operated in compliance with the terms and conditions of this General Permit. The Authorization to Use GP-5A shall cease if the owner or operator fails to submit any additional information requested by the Department to process the application by the specified deadline.
- (d) *Transfer of Ownership.* The Authorization to Use GP-5A may not be transferred from the owner or operator of a facility except when the change of ownership is demonstrated to the satisfaction of the Department and the Department approves the transfer in writing. Within 30 calendar days after a transfer of ownership of the facility, the new owner or operator shall submit an appropriate form or application to the Air Program Manager of the appropriate Regional Office. If the owner or operator is modifying any existing source or adding a new source at the facility currently authorized by the General Permit, the owner or operator shall submit an Application for Authorization to Use GP-5A in accordance with Condition 6(a) above. If there are equipment or activities located on the same site or on sites that share equipment and are within ¼ mile of each other, the owner or operator shall submit an Application for Authorization to Use GP-5A as a General Plan Approval with a \$1,000 application

fee. If the owner or operator is not modifying any existing source, not adding a new source, or not subject to a new Single Source Determination based on the transfer of ownership, the owner or operator shall submit a Transfer of Ownership form with a \$300 fee. The employer I.D. number (Federal IRS No.) shall be used as a test to determine if a transfer of ownership has occurred.

- (e) *Administrative Amendment.* In the event of a change in the name, address, or telephone number of a person identified in the General Permit Application or a similar minor administrative change at the facility, the Department may authorize an administrative amendment. The owner or operator shall submit a brief description of the change and the date on which the change is to occur in a letter signed by the Responsible Official with the fee specified in Condition 7(e) to the Air Program Manager of the appropriate Regional Office.
- (f) *Modification, Suspension, or Revocation of GP-5A or Authorizations to Use GP-5A.*
 - (i) The Department may modify, suspend, or revoke and reissue this General Permit if it is determined that GP-5A does not comply with the Clean Air Act, the APCA, or regulations adopted under the acts.
 - (ii) This General Permit may be modified, suspended, or revoked if the Department determines that the unconventional natural gas well site operation or remote pigging station cannot be adequately regulated under this General Permit.
 - (iii) An Authorization to Use GP-5A may be suspended or revoked if the Department determines that, at any time, the owner or operator has failed to construct and/or operate the facility in compliance with the terms and conditions of this General Permit, the specifications in the Application for Authorization to Use GP-5A, or the information provided in the supplemental material included with the application used to determine if the proposed sources will comply with the GP-5A.
 - (iv) Upon suspension or revocation of an Authorization to Use GP-5A, the owner or operator shall immediately cease construction and/or operation of the facility. The owner or operator of the facility shall not restart construction and/or operation prior to the receipt of written approval from the Department.

7. General Permit Fees

Each applicant seeking Authorization to Use GP-5A shall submit the applicable fees required under this Condition to the appropriate DEP Regional Office. The following fee schedules apply to this General Permit:

- (a) General Plan Approval Application Fee for Sources Subject to and Review of NSPS, payable upon submission of the application: \$1,700
- (b) General Plan Approval Application Fee with new Single Source Determination, payable upon submission of the application: \$1,000
- (c) General Operating Permit Application Fee, payable upon submission of the application: \$ 375
- (d) Annual Operating Permit Administration Fee, payable by March 1st for the previous calendar year: \$ 375
- (e) Administrative Amendment Fee, payable upon submission of the letter in Condition 6(e): \$ 300
- (f) The Department may increase the applicable fees for this General Plan Approval/General Operating Permit in accordance with the applicable fee schedules in 25 Pa. Code Chapter 127, Subchapter I following notice in the *Pennsylvania Bulletin*.

8. Applicable Laws

- (a) It is the duty of the Responsible Official, as defined in 25 Pa. Code § 121.1, to ensure that the facility is in compliance with all applicable federal, state, and local laws and regulations, including 25 Pa. Code, Subpart C, Article III. Nothing in this General Permit relieves the Responsible Official from this obligation to comply.
- (b) Applicable federal regulations may include, but are not limited to, the following New Source Performance Standards (NSPS), codified at 40 CFR Part 60 and incorporated by reference in 25 Pa. Code § 122.3, and National Emission Standards for Hazardous Air Pollutants (NESHAP), codified at 40 CFR Part 63 and incorporated by reference in 25 Pa. Code § 127.35:
 - (i) **40 CFR Part 60, Subpart JJJJ** – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.

- (ii) **40 CFR Part 60, Subpart OOOO** – Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution for which Construction, Modification, or Reconstruction Commenced after August 23, 2011, and on or before September 18, 2015.
- (iii) **40 CFR Part 60, Subpart OOOOa** – Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015.
- (iv) **40 CFR Part 63, Subpart HH** – National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities.
- (v) **40 CFR Part 63, Subpart ZZZZ** – National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines.

9. Best Available Technology Requirements

New sources are required to control the emission of air pollutants to the maximum extent, consistent with best available technology (BAT) as determined by the Department as of the date of issuance of the plan approval for the new source as required under 25 Pa. Code § 127.1. Condition 1 (BAT Compliance Requirements) of Sections B through L of this General Permit are determined to meet the BAT requirements.

10. Compliance Requirements and Compliance Certification

- (a) The emissions from all sources and associated air pollution control equipment located at an unconventional natural gas well site or remote pigging station and other sources determined by the Department to be a single source shall not equal or exceed either of the following on a 12-month rolling sum basis:
 - (i) Nitrogen Oxides (NO_x) – 100 tons
 - (ii) Carbon Monoxide (CO) – 100 tons
 - (iii) Sulfur Oxides (SO_x) – 100 tons
 - (iv) Particulate Matter with an aerodynamic diameter less than 10 microns (PM₁₀) – 100 tons
 - (v) Particulate Matter with an aerodynamic diameter less than 2.5 microns (PM_{2.5}) – 100 tons
 - (vi) Volatile Organic Compounds (VOC) – 50 tons
 - (vii) Any individual Hazardous Air Pollutant (HAP) – 10 tons
 - (viii) Total Hazardous Air Pollutants (HAP) – 25 tons
 - (ix) In addition, the emissions from all sources and associated air pollution control equipment located at a facility in Bucks, Chester, Delaware, Montgomery, or Philadelphia Counties shall not equal or exceed any of the following on a 12-month rolling sum basis:
 - (A) NO_x – 25 tons
 - (B) VOC – 25 tons
- (b) The facility throughput, hours of operation, and/or emissions from sources at the facility shall be constrained as necessary to not exceed any facility-wide emissions cap required in (a) above.
- (c) All sources and associated air pollution control equipment located at a facility shall be:
 - (i) Operated in such a manner as not to cause air pollution, as that term is defined in 25 Pa. Code § 121.1;
 - (ii) Operated and maintained in accordance with the manufacturer's specifications, procedures, and recommended maintenance schedule, as provided in the Application for Authorization to Use GP-5A, or an alternate procedure approved by the Department that achieves equal or greater emissions reductions in accordance with 25 Pa. Code § 127.12b;
 - (iii) Operated and maintained in accordance with the fugitive emission requirements of 25 Pa. Code § 123.1 and § 123.2; **and**
 - (iv) Operated and maintained in such a manner that malodors are not detectable outside the property of the owner or operator on whose land the facility is being operated in accordance with 25 Pa. Code § 123.31.

- (d) The owner or operator of an existing facility where a new well is drilled, hydraulically fractured, hydraulically refractured or where a new equipment is installed or an existing source is modified shall comply with applicable BAT requirements established in this General Permit.
- (e) This General Permit cannot be used to relax BAT or other emission limitations or requirements previously established through the air quality permitting process.
- (f) An owner or operator of a facility may apply to the Department for a plan approval for any air contamination source in lieu of seeking authorization to use the General Permit for unconventional natural gas well sites or remote pigging stations.
- (g) The owner or operator authorized to use this General Permit shall comply with the specifications in the application and the terms and conditions of this General Permit.
- (h) The owner or operator of the facility shall submit to the Air Program Manager of the appropriate DEP Regional Office an annual certification of compliance with the terms and conditions in the GP-5A for the previous year, including the emission limitations, standards, or work practices. This Compliance Certification Form must be included in the annual report as outlined in Condition 13(c)(vii).

11. Notification Requirements

- (a) *Municipal Notification.* The facility owner or operator proposing to use this General Permit shall notify the local municipality and county where the air pollution source is to be located that they have applied for an Authorization to Use GP-5A. The notification shall clearly describe the proposed sources and/or modifications.
- (b) The owner or operator shall notify the Air Program Manager of the appropriate DEP Regional Office, in writing, at least five business days prior to the commencement of operation of a source of their intent to do so. The owner or operator shall also include the date of completion of construction of the source in the notice. When multiple sources at the facility are subject to different commencement of operation schedules, written notice shall be submitted to DEP prior to the commencement of operation of each source. The owner or operator may submit a single written notice for multiple sources.
- (c) *Malfunctions.*
 - (i) Any malfunction that poses an imminent danger to the public health, safety, or welfare or to the environment shall be reported by telephone to the County Emergency Management Agency and to the 24 hour Emergency Hotline at 1-800-541-2050 no later than one hour after the discovery of an incident. Following the telephone or email notification, a written notice as specified in (iv) below shall be submitted to DEP within three business days.
 - (ii) Any malfunction that does not pose an imminent danger to the public health, safety, or welfare or to the environment shall follow the guidance provided in the [GP-5 and GP-5A Malfunction Reporting Instructions](#) and, if required to report, shall notify the Air Program Manager of the appropriate DEP Regional Office by telephone or email within 24 hours of discovery. Following the telephone or email notification, a written notice as specified in (iv) below shall be submitted to DEP within five business days.
 - (iii) If the owner or operator is unable to provide notification by telephone to the Air Program Manager of the appropriate DEP Regional Office within 24 hours of the discovery of a malfunction due to a weekend or holiday, the notification shall be made to the Department no later than 4:00 pm on the first business day following the weekend or holiday.
 - (iv) Written notification shall include:
 - (A) The name, GP-5A authorization number, and location of the facility;
 - (B) The nature and cause of the malfunction or incident;
 - (C) The date and time when the malfunction, incident, or breakdown was first discovered;
 - (D) The expected duration of increased emissions;
 - (E) The estimated rate of emissions for all criteria, hazardous, and greenhouse gas pollutants; **and**
 - (F) Any changes to the equipment or modification of the procedures that will prevent future reoccurrences of the malfunction.

- (v) The owner or operator shall notify the Air Program Manager of the appropriate DEP Regional Office by telephone or email within 24 hours of when corrective measures have been implemented.
- (vi) Any emissions due to a malfunction are to be reported in the annual emissions inventory report required in Condition 13(d).

12. Recordkeeping Requirements

- (a) All records required must be maintained onsite or at the nearest local field office for a minimum of 5 years and may be maintained in electronic format.
- (b) The owner or operator of the facility shall generate and maintain records that clearly demonstrate to the Department that the facility is not a Title V facility and that the facility is in compliance with facility-wide emission limitations. At a minimum, the records shall be maintained on a monthly basis, and the actual emissions shall be calculated on a 12-month rolling sum. The Department reserves the right to request additional information necessary to determine compliance with the General Permit.
- (c) The owner or operator of the facility shall keep records of all written notifications required under permit conditions.

13. Reporting Requirements

- (a) The owner or operator of an unconventional natural gas well site or remote pigging station shall submit to the Air Program Manager of the appropriate DEP Regional Office all requests, reports, applications, submittals, and other communications concerning applicable federal NSPS and NESHAP.
- (b) In accordance with 40 CFR §§ 60.4 and 63.10, copies of all requests, reports, applications, submittals, and other communications shall also be submitted to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI) accessible at <https://cdx.epa.gov> unless electronic reporting is not available, in which case a copy shall be sent to the following address:

United States Environmental Protection Agency, Region III
Office of Air Enforcement and Compliance Assistance (3AP20)
1650 Arch St.
Philadelphia, PA 19103-2029

- (c) The annual report is required to be submitted either in electronic format, by hand-delivery, courier, or sent by certified mail, return receipt requested, to the Air Program Manager of the appropriate DEP Regional Office. The reporting period specified by the owner/operator shall be no later than one year from the start of operations of the facility, unless otherwise approved by the Department. The initial and subsequent annual reports shall be submitted within 60 days of the end of the reporting periods. General information required on all reports includes:
 - (i) Company Name;
 - (ii) Facility Site Name;
 - (iii) The GP-5A authorization number;
 - (iv) US Well ID(s);
 - (v) Either:
 - (A) The address of the site; or
 - (B) A description of the site and the location using latitude and longitude coordinates of the site in decimal degrees to an accuracy and precision of 5 decimal degrees using the North American Datum of 1983;
 - (vi) The beginning and ending dates of the reporting period;
 - (vii) The Certification Form described in Condition 10(h), which must include:
 - (A) The statement: "Based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete."; and
 - (B) The signature of the certifying Responsible Official;
 - (viii) Identification of each source included in the report;

- (ix) The identification of each term or condition of the GP-5A that is the basis of the certification, the compliance status, and the methods used for determining the compliance status of the source, currently and over the reporting period as identified in Sections B through L of this General Permit; **and**
 - (x) The records of the facility's emissions to demonstrate compliance with Condition 12(b).
- (d) In accordance with 25 Pa. Code § 135.3, the owner or operator of a facility shall submit to the Department via AES*Online or AES*XML at www.depgreenport.state.pa.us/ by March 1st of each year, a facility inventory report for the preceding calendar year for all sources regulated under this General Permit. The inventory report shall include all emissions information for all sources operated during the preceding calendar year from the annual report required in (c) above. Emissions data including, but not limited to, the following shall be reported:
- (i) NO_x;
 - (ii) CO;
 - (iii) SO_x;
 - (iv) PM₁₀;
 - (v) PM_{2.5};
 - (vi) VOC;
 - (vii) Speciated HAP including, but not limited to, benzene, ethyl benzene, formaldehyde, n-hexane, toluene, isomers and mixtures of xylenes, and 2,2,4-trimethylpentane;
 - (viii) Total HAP;
 - (ix) CO₂;
 - (x) CH₄; **and**
 - (xi) N₂O.

14. Source Testing Requirements

- (a) In addition to the specific performance testing requirements included in this General Permit, the Department may require the owner or operator to conduct a source test if it is determined that the air contaminant emissions from a source operating under this General Permit are, or may be, in excess of an applicable air contaminant emission limitation.
- (b) The Department may alter the frequency of performance test requirements for reauthorization based on available performance data from the source, unless required by federal regulation.
- (c) All testing, with the exception of periodic monitoring, shall be performed in accordance with any applicable federal regulations, 25 Pa. Code, Chapter 139 and the current version of the Department's Source Testing Manual, or an alternative test method as approved by the Department.
- (d) All submittals, with the exception of periodic monitoring data, shall meet the applicable requirements specified in the most current version of the Department's Source Testing Manual.
- (e) One electronic copy **and** one printed copy of all reports, protocols, and test completion notifications, with the exception of periodic monitoring data, shall be submitted either by hand-delivery, courier, or sent by certified mail, return receipt requested, to the Air Program Manager of the appropriate DEP Regional Office **and** to the PSIMS Administrator for the Source Testing Section in DEP's Central Office.
- (f) At least 60 calendar days prior to commencing an emission testing program to demonstrate compliance required by this General Permit, a test protocol shall be submitted in accordance with (e) above for review and approval. An operator may request an approval from the Department for a test protocol that covers testing of all currently operated and future sources in service at that operator's various facilities. In such a request, the Operator will submit the test protocol in accordance with (e) above for review and approval and include a list of currently permitted engines (to be updated as necessary when engines are installed or removed). If the owner or operator has a test protocol, previously approved by the Department, a new test protocol does not need to be submitted for review/approval, provided that there are no changes, including the testing contractor, and the owner/operator agrees to comply with all conditions of acceptance in the letter approving the protocol.

- (g) At least 30 calendar days prior to commencing an emission testing program to demonstrate compliance required by this General Permit, written notification of the date and time of testing shall be provided to the Department's Division of Source Testing and Monitoring and the appropriate DEP Regional Office so that an observer may be present. The Department is under no obligation to accept the results of any testing performed without adequate advance written notice to the Department of such testing.
- (h) Within 15 calendar days after completion of the on-site testing portion of an emission test program to demonstrate compliance required by this General Permit, if a complete test report has not yet been submitted, an electronic notification shall be submitted in accordance with (e) above indicating the completion date of the on-site testing.
- (i) A complete test report shall be submitted in accordance with (e) above no later than 60 calendar days after completion of the on-site testing portion of an emission test program required by this General Permit. The complete test report shall include a summary at the beginning of the report which includes:
 - (i) A statement that the owner or operator has reviewed the report from the emissions testing company and agrees with the findings;
 - (ii) The GP-5A authorization number and conditions that are the basis for the evaluation;
 - (iii) A summary of results with respect to each applicable permit condition; **and**
 - (iv) A statement of compliance or non-compliance with each applicable permit condition.

15. De Minimis Emission Increases

- (a) Additional equipment may be installed, or currently authorized equipment may be modified at the facility without additional authorization provided that the following conditions (i) through (ii) are met. Replacement unit as defined in 25 Pa. Code § 121.1 may be installed without additional authorization provided that the following conditions (ii) through (iii) are met.
 - (i) The owner or operator complies with the requirements of 25 Pa. Code § 127.449(a), (b), and (d) through (i);
 - (ii) The equipment being installed, modified, or replaced meets the current applicable BAT Compliance Requirements;
 - (iii) The owner or operator submits written notification in accordance with Condition 11(b), including the following additional information:
 - (A) The manufacturer, model, rated capacity, and serial number of the equipment;
 - (B) A certification from the owner or operator that the equipment will meet all applicable terms and conditions of this General Permit, including Condition 10(a);
 - (C) The notification shall be signed by a Responsible Official and shall acknowledge that the certifying party is aware of the penalties for unsworn falsification to governmental authorities as established under 18 Pa. C.S. § 4904. The certification shall also state that based on information and belief formed after reasonable inquiry, that the information in the notice is true, accurate, and complete; **and**
 - (D) The notice shall identify and describe the pollutants that will be emitted as a result of the de minimis emissions increase and provide emission rates in tons per year and in terms necessary to establish compliance with any applicable requirement.
- (b) A new Authorization to Use GP-5A shall be required if an owner or operator chooses to employ Selective Catalytic Reduction (SCR) to comply with NO_x emission standards in Section C Condition 1(c).

SECTION B. GLYCOL DEHYDRATION UNITS

1. BAT Compliance Requirements

- (a) For each glycol dehydration unit constructed and authorized to operate under GP-5 approved by the Department prior to February 2, 2013, with a total uncontrolled potential VOC emission rate greater than 10 tpy, the owner or operator shall control VOC emissions from the glycol dehydrator still vent stream by at least 85% with a

condenser, flare, thermal oxidizer, vapor recovery unit, or other air cleaning device approved by the Department that meets the applicable requirements in Section J.

- (b) For each glycol dehydration unit constructed and authorized to operate on or after August 10, 2013, but prior to August 8, 2018, with a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, the owner or operator shall control VOC emissions from the glycol dehydrator still vent stream by at least 95% with a condenser, enclosed flare, thermal oxidizer, vapor recovery unit, or other air cleaning device approved by the Department that meets the applicable requirements in Section J.
- (c) For each glycol dehydrator constructed and authorized to operate on or after August 8, 2018, with a methane emission rate of 200 tpy or greater, a VOC emission rate of 2.7 tpy or greater, an single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, the owner or operator shall control methane, VOC, and HAP emissions from the glycol dehydrator still vent stream by at least 95% using an enclosed flare or other combustion device or other air cleaning device approved by the Department that meets the applicable requirements in Section J.
- (d) Associated equipment, such as natural gas-driven pneumatic controllers (Section H), natural gas-driven pneumatic pumps (Section I), and fugitive emissions components (Section G) are subject to the requirements of their respective Sections.
- (e) If any glycol dehydration unit uses triethylene glycol for the dehydration process, has a natural gas throughput greater than 3 MMscf/d, and emits more than 1.0 tpy of benzene, the owner or operator must:
 - (i) Determine the natural gas throughput in accordance with 40 CFR § 63.772(b)(1).
 - (ii) Determine the actual average benzene or benzene, toluene, ethylbenzene and xylene (BTEX) emissions in accordance with 40 CFR § 63.772(b)(2).
 - (iii) If the glycol dehydration unit is located at a facility located within an urbanized area plus offset or urban cluster boundary, the owner or operator shall meet the requirements of 40 CFR § 63.764(d)(1).
 - (iv) If the glycol dehydration unit is located at a facility that is not within an urbanized area plus offset or urban cluster boundary, the owner or operator shall meet the requirements of 40 CFR § 63.764(d)(2).
 - (v) If an alternate circulation rate is required, the determination must be submitted in accordance with 40 CFR § 63.764(d)(2)(ii).

2. Recordkeeping Requirements

For each glycol dehydration unit, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

- (a) The location of the glycol dehydration unit;
- (b) The calculation for the optimum glycol circulation rate or the alternative glycol circulation rate in accordance with 40 CFR § 63.775(c)(7), if applicable;
- (c) The determination of the actual average benzene or BTEX emissions in accordance with 40 CFR § 63.774(d)(1), if applicable;
- (d) The emissions calculations for each glycol dehydrator in accordance with 25 Pa. Code § 135.5; and
- (e) Records of deviations and malfunctions in accordance with 40 CFR § 63.774(g), if applicable.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each glycol dehydration unit operated during the reporting period shall include:

- (a) The records of the optimum or alternative glycol circulation rate in accordance with 40 CFR § 63.775(c)(7), if applicable; and
- (b) The records of any deviations and malfunctions in accordance with 40 CFR § 63.775(c)(6), if applicable.

The emissions from each glycol dehydration unit in operation during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION C. STATIONARY NATURAL GAS-FIRED SPARK IGNITION INTERNAL COMBUSTION ENGINES

1. BAT Compliance Requirements

(a) For each natural gas-fired spark ignition internal combustion engine constructed and authorized to operate under GP-5 approved by the Department on or after March 10, 1997 but prior to February 2, 2013, the owner or operator shall:

- (i) Operate or equip the engine with air cleaning devices to meet the following emission levels:
 - (A) NO_x (as NO₂) of 2.0 g/bhp-h while operating at rated bhp and speed;
 - (B) Non-Methane Non-Ethane Hydrocarbon (NMNEHC) as propane, excluding formaldehyde, of 2.0 g/bhp-h while operating at rated bhp and speed; and
 - (C) CO of 2.0 g/bhp-h while operating at rated bhp and speed.
- (ii) Ensure that at operating conditions less than rated capacity, the engine shall on a lb/h basis emit no more than it would emit at rated bhp and speed.
- (iii) Ensure the engine meets the applicable requirements of (d) below.

(b) For each natural gas-fired spark ignition internal combustion engine constructed and authorized to operate under GP-5 approved by the Department on or after February 2, 2013, but prior to August 8, 2018, the owner or operator shall:

- (i) Ensure the engine does not exceed the emissions standards specified in the following table:

Engine Type	Rated bhp	NO _x	CO	NMNEHC (as propane) excluding HCHO	HCHO
Lean-Burn	≤100	2.0 g/bhp-h	2.0 g/bhp-h	-	-
Lean-Burn	>100 - ≤500	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	-
Lean-Burn	>500	0.50 g/bhp-h	47 ppmvd @ 15% O ₂ <u>or</u> 93% reduction	0.25 g/bhp-h	0.05 g/bhp-h
Rich-Burn	≤100	2.0 g/bhp-h	2.0 g/bhp-h	-	-
Rich-Burn	>100 - ≤500	0.25 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	-
Rich-Burn	>500	0.20 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	2.7 ppmvd @ 15% O ₂ <u>or</u> 76% reduction

- (ii) Ensure the engine meets the applicable requirements of (d) below.

(c) For each natural gas-fired spark ignition internal combustion engine constructed and authorized to operate on or after August 8, 2018, the owner or operator shall:

(i) Ensure the engine does not exceed the emission standards specified in the following table:

Engine Type	Rated bhp	NO _x	CO	NMNEHC (as propane) excluding HCHO	HCHO
Lean-Burn	<100	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	-
Lean-Burn	≥100 - ≤500	1.0 g/bhp-h	0.70 g/bhp-h	0.30 g/bhp-h	-
Lean-Burn	>500 - <2,370	0.50 g/bhp-h	0.25 g/bhp-h	0.25 g/bhp-h	0.05 g/bhp-h
Lean-Burn	≥2,370	0.30 g/bhp-h Uncontrolled <u>or</u> 0.05 g/bhp-h with Control	0.25 g/bhp-h	0.25 g/bhp-h	0.05 g/bhp-h
Rich-Burn	<100	1.0 g/bhp-h	2.0 g/bhp-h	0.70 g/bhp-h	
Rich-Burn	≥100 - ≤500	0.25 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	-
Rich-Burn	>500	0.20 g/bhp-h	0.30 g/bhp-h	0.20 g/bhp-h	2.7 ppmvd @ 15% O ₂ <u>or</u> 76% reduction

(ii) Ensure that for engines that control NO_x emissions with a control technology that uses ammonia or urea as a reagent, the exhaust ammonia slip is limited to 10 ppmvd or less corrected to 15% O₂.

(iii) Ensure the engine meets the applicable requirements of (d) below.

(d) The owner or operator of the engine shall also:

(i) Comply with the applicable requirements of 40 CFR Part 63, Subpart ZZZZ for engines constructed (as defined in Subpart ZZZZ) prior to June 12, 2006;

(ii) Ensure the engine meets the visible emissions standards, as determined by the methods described in 25 Pa. Code § 123.43, by not exceeding the following limitations:

(A) Equal to or greater than 10% for a period or periods aggregating more than three minutes in any one hour; **and**

(B) Equal to or greater than 30% at any time

(iii) Install, operate, and maintain a non-resettable hour meter;

(iv) Limit the engine's time spent at idle during startup or shutdown to a period appropriate for the operation of the engine and air pollution control equipment consistent with good air pollution control practices, not to exceed 30 minutes, during which time the emissions standards in (b) through (d) do not apply.

- (v) Conduct performance tests and periodic monitoring for the engine as detailed in Conditions 4 and 5 of this section on the following schedule:

Engine Size hp	Initial Compliance Performance Test	Continuous Compliance Performance Test	Periodic Monitoring
<100	None Required	None Required	Every 2,500 hours of operation
≥100 - ≤500	Within 180 days of startup of the engine	Within 180 days of each reauthorization	Every 2,500 hours of operation
>500 and not subject to (d)(i)	Within 180 days of startup of the engine	Every 8,760 hours of operation <u>or</u> every three years <u>and</u> within 180 days of each reauthorization	Every 2,500 hours of operation
>500 and subject to (d)(i)	Not Applicable	Every year	Every 2,500 hours of operation

- (A) For an engine greater than or equal to 100 hp and less than or equal to 500 hp, if the engine is certified by the manufacturer in accordance with 40 CFR Part 60, Subpart JJJJ and the owner or operator operates and maintains the engine in accordance with the manufacturer's instructions, the performance testing requirements are waived.
- (B) For an engine greater than 500 hp, if the engine is certified by the manufacturer in accordance with 40 CFR Part 60, Subpart JJJJ and the owner or operator operates and maintains the engine in accordance with the manufacturer's instructions, the continuous compliance performance testing requirements every 8,760 hours of operation or every three years are waived.
- (C) The Department may alter the frequency of periodic monitoring based on the test results. The frequency of periodic monitoring may be altered upon request of the owner or operator with written Departmental approval.

2. Recordkeeping Requirements

For each engine, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

- The GP-5A authorization number and the date each engine was authorized for use;
- The make, model, and serial number of each engine;
- Either a copy of the manufacturer's maintenance instructions or an alternative maintenance plan;
- Records of maintenance conducted on each engine and any installed air pollution control devices;
- A copy of the manufacturer's engine certification or vendor guarantees;
- The results of each periodic monitoring;
- The summary for each complete test report described in Section A Condition 14(i); and
- The emissions calculations for each engine in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

The emissions from each natural gas-fired spark ignition internal combustion engine in operation during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

4. Engine Performance Testing Requirements

- When conducting a performance test for an engine, the owner or operator must submit the test protocol described in Section A Condition 14(f) for review and approval.
- The owner or operator should conduct the following test procedures:
 - Conduct three test runs of at least one-hour duration within 10% of 100% peak (or the highest achievable) load.

- (ii) Select the sampling port location and the number and location of traverse points at the exhaust using 40 CFR Part 60, Appendix A-1, Method 1 or 1A depending on stack diameter, or the sampling points selected according to 40 CFR Part 60, Appendix A-4, Method 7E Section 8.1.2.
- (iii) Determine the effluent characteristics by either:
 - (A) Calculating the exhaust flow in accordance with 40 CFR Part 60, Appendix A-7, Method 19 and measuring the O₂ concentration using 40 CFR Part 60, Appendix A-2, Method 3A; **or**
 - (B) By measuring:
 - (1) The flow velocity, stack temperature, static pressure, and barometric pressure using 40 CFR Part 60, Appendix A-1, Method 2 or 2C depending on stack diameter;
 - (2) The gas density using 40 CFR Part 60, Appendix A-2, Method 3A; **and**
 - (3) The moisture content using 40 CFR Part 60, Appendix A-3, Method 4.
- (iv) Simultaneous to the determination of the O₂ concentration in (iii)(A) or (B) above, determine:
 - (A) The NO_x concentration of the exhaust gas using 40 CFR Part 60, Appendix A-4, Method 7E;
 - (B) The CO concentration of the exhaust gas using 40 CFR Part 60, Appendix A-4, Method 10;
 - (C) The NMNEHC concentration, as propane, excluding formaldehyde of the exhaust gas using ALT-106 **and**
 - (D) The formaldehyde concentration of the exhaust gas, **if applicable**, using 40 CFR Part 63, Appendix A, Method 320.
- (c) If at any time the owner or operator operates the engine in excess of the highest achievable load plus 10%, the owner or operator must perform a stack test within 180 days from the anomalous operation.

5. Engine Periodic Monitoring Requirements

- (a) When conducting periodic monitoring on an engine, the owner or operator may follow the procedures in (b) below. If the owner or operator decides to deviate from those procedures, they must submit a request to use an alternate procedure, in writing, at least 60 days prior to performing the periodic monitoring. In the alternate procedure request, the owner or operator must demonstrate the alternate procedure's equivalence to the standard procedure to the satisfaction of the Division of Source Testing and Monitoring.
- (b) *Standardized Periodic Monitoring Procedure.*
 - (i) Conduct three test runs of at least 20 minutes duration within 10% of 100% peak (or the highest achievable) load.
 - (ii) Determine NO_x and CO emissions and O₂ concentrations in the exhaust with either an electro-chemical cell portable gas analyzer used and maintained in accordance with the manufacturer's specifications and following the procedures specified in the current version of ASTM D6522 or by following the procedures in 4(b) (ii) – (iv) B) of this section.
 - (iii) If the measured NO_x or CO emissions concentrations are in exceedance of the emissions limit, the owner or operator must perform a stack test in accordance with the Performance Testing Requirements of Condition 4 above, within 180 days of the periodic monitoring.
- (c) The 2,500 hours of operation count resets after any performance test performed in accordance with Condition 4 above.
- (d) For engines constructed (as defined in that subpart) and authorized to operate prior to June 12, 2006, that installed a continuous parametric monitoring system (CPMS) to monitor the catalyst inlet temperature, the owner or operator must install, operate, and maintain the CPMS according to 40 CFR § 63.6625(b)(1) through (6).

SECTION D. RECIPROCATING COMPRESSORS

1. BAT Compliance Requirements

The owner or operator of a reciprocating compressor constructed and authorized to operate on or after August 8, 2018, shall either:

- (a) Replace the reciprocating compressor rod packing either:
 - (i) On or before 26,000 hours of operation from the initial startup date or most recent rod packing replacement; or
 - (ii) Prior to 36 months from the initial startup date of the reciprocating compressor or the date of the most recent rod packing replacement; or
- (b) Collect the methane, VOC, and HAP emissions from the rod packing using a collection system that operates under negative pressure and routes the emissions to a process through a closed vent system that meets the applicable requirements of Section J.

2. Recordkeeping Requirements

For each reciprocating compressor, the owner or operator shall maintain records in accordance with Section A Condition 12, including information on:

- (a) The location of the reciprocating compressor;
- (b) The US Well Number the reciprocating compressor is associated with;
- (c) The date and time of the initial startup of the reciprocating compressor;
- (d) The date and time of the most recent rod packing replacement;
- (e) The cumulative number of hours of operation or number of months since the initial startup of the reciprocating compressor or most recent rod packing replacement; and
- (f) The date and time of installation of a rod packing emissions collection system and closed vent system.

In addition, records of the emissions calculation for each reciprocating compressor must be kept in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each reciprocating compressor operated during the reporting period shall include either:

- (a) The records of the cumulative number of hours of operation or number of months since the startup of the reciprocation compressor or most recent rod packing replacement; or
- (b) A statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

The emissions from each reciprocating compressor in operation during the reporting period must be included in the emissions inventory report of Section A Condition 13(d), including the emissions from scheduled and unscheduled blowdowns.

SECTION E. STORAGE VESSELS

1. BAT Compliance Requirements

- (a) For each storage vessel constructed and authorized to operate on or after August 23, 2011, but prior to August 10, 2013, the owner or operator shall meet the applicable requirements of 40 CFR §§ 60.5365(e) and 60.5395(d) and (e).
- (b) For each storage vessel constructed and authorized to operate on or after August 10, 2013, but prior to August 8, 2018, with a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, the owner or operator shall equip the storage vessel with a cover and route all vapor through a closed vent system to a control device that reduces VOC emissions by 95% or more

by meeting the applicable control, cover, and closed vent system requirements of Section J Condition 1(a) through (f) or any alternative method approved by the Department.

- (c) For each storage vessel constructed and authorized to operate on or after August 8, 2018, with a methane emission rate of 200 tpy or greater, a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, the owner or operator shall equip the storage vessel with a cover and route all vapor through a closed vent system to a control device that reduces methane, VOC, and HAP emissions by 95% or more by meeting the applicable control, cover, and closed vent system requirements of Section J Condition 1(a) through (f) or any alternative method approved by the Department.
- (d) Any storage vessel returned to service must meet the requirements of 40 CFR § 60.5395(f) or § 60.5395a(c).
- (e) Any storage vessel with a capacity greater than or equal to 2,000 gallons and less than or equal to 40,000 gallons must meet the requirements of 25 Pa. Code § 129.57.
- (f) Any storage vessel with a capacity greater than or equal to 40,000 gallons must meet the requirements of 25 Pa. Code § 129.56, **if applicable**.

2. Recordkeeping Requirements

For each storage vessel, the owner or operator shall maintain records in accordance with Section A Condition 12 and 40 CFR § 60.5420(c)(5) or § 60.5420a(c)(5) as applicable.

In addition, the emissions calculation for each storage vessel, which may be calculated using Department-approved methods such as direct measurement; modeling programs such as the most recent version of EPA TANKS, ProMax, and API E&P Tanks; process simulation software such as HYSIM, HYSIS, WINSIM, and PROSIM; or calculation methodologies such as the Vazquez-Beggs equation, must be kept in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each storage vessel in operation during the reporting period shall be submitted in accordance with 40 CFR § 60.5420(b)(6) or § 60.5420a(b)(6) as applicable.

The emissions from each storage vessel operating during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION F. TANKER TRUCK LOAD-OUT OPERATIONS

1. BAT Compliance Requirements

- (a) For all truck load-out operations that service a storage vessel with a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, where the loading rack was constructed and authorized to operate on or after August 10, 2013, but prior to August 8, 2018, the owner or operator shall:
 - (i) Use a vapor balancing system when removing liquids from the storage vessel; **and**
 - (ii) Ensure that each tanker truck that is used to remove liquids from the storage vessel has passed one of the following annual leak tests:
 - (A) A tanker truck that does not indicate more than 1" H₂O pressure change within 5 minutes after being pressurized to 18" H₂O and after being depressurized to 6" H₂O vacuum has passed a MACT-level test and is assumed to have a collection efficiency of 99.2%.
 - (B) A tanker truck that does not indicate more than 3" H₂O pressure change within 5 minutes after being pressurized to 18" H₂O and after being depressurized to 6" H₂O vacuum has passed an NSPS-level test and is assumed to have a collection efficiency of 98.7%.
 - (C) A tanker truck that has passed a leak test performed in accordance with 49 CFR § 180.407 is accepted as equivalent to an NSPS-level collection efficiency of 98.7%.
 - (D) A tanker truck that has passed a leak test performed in accordance with 40 CFR Part 60, Appendix A-8, Method 27 is accepted as equivalent to an NSPS-level collection efficiency of 98.7%.
 - (iii) As an alternative, VOC emissions must be controlled with 95% or greater efficiency.

- (b) For all truck load-out operations that service a storage vessel with a total methane emission rate of 200 tpy or greater, a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, where the loading rack was constructed and authorized to operate on or after August 8, 2018, the owner or operator shall:
- (i) Use a vapor balancing system when removing liquids from the storage vessel; **and**
 - (ii) Ensure that each tanker truck that is used to remove liquids from the storage vessel has passed one of the following annual leak tests:
 - (A) A tanker truck that does not indicate more than 1" H₂O pressure change within 5 minutes after being pressurized to 18" H₂O and after being depressurized to 6" H₂O vacuum has passed a MACT-level test and is assumed to have a collection efficiency of 99.2%.
 - (B) A tanker truck that does not indicate more than 3" H₂O pressure change within 5 minutes after being pressurized to 18" H₂O and after being depressurized to 6" H₂O vacuum has passed an NSPS-level test and is assumed to have a collection efficiency of 98.7%.
 - (C) A tanker truck that has passed a leak test performed in accordance with 49 CFR § 180.407 is accepted as equivalent to an NSPS-level collection efficiency of 98.7%.
 - (D) A tanker truck that has passed a leak test performed in accordance with 40 CFR Part 60, Appendix A-8, Method 27 is accepted as equivalent to an NSPS-level collection efficiency of 98.7%.
 - (iii) As an alternative to (i) and (ii), VOC emissions must be controlled with 95% or greater efficiency.

2. Recordkeeping Requirements

For each tanker truck load-out operation, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

- (a) The identification, location, and date of construction of each vapor recovery load-out system;
- (b) Records of each tanker truck load-out operation including the date and time of the liquids load-out, the type and volume of liquids loaded, and the truck collection efficiency based on the annual leak test; and
- (c) The emissions calculation for each tanker truck load-out operation in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

The emissions from tanker truck load-out operations during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION G. FUGITIVE EMISSIONS COMPONENTS

1. BAT Compliance Requirements

- (a) No later than 30 days after an emission source commences operation, and at least monthly thereafter, the owner or operator of a facility shall conduct an Auditory, Visual, or Olfactory (AVO) inspection.
- (b) No later than 60 days after the start of production, and quarterly thereafter, the owner or operator shall conduct an LDAR program using either an OGI camera, a gas leak detector that meets the requirements of 40 CFR Part 60, Appendix A-7, Method 21, or other leak detection methods approved by the Division of Source Testing and Monitoring.
 - (i) The owner or operator of a well that is temporarily shut-in is not required to perform LDAR until 60 days after the well is put into production or the next quarterly inspection.
 - (ii) The owner or operator may request, in writing, an extension of the LDAR inspection interval from the Air Program Manager of the appropriate DEP Regional Office.
 - (iii) Any fugitive emissions components that are difficult-to-monitor or unsafe-to-monitor must be identified in the monitoring plan described in Condition 2(a).
 - (iv) The owner or operator may track the number of leaking components in the LDAR records and decrease the LDAR inspection interval from quarterly to semi-annually if the percentage of leaking components is

less than 2.0% for two consecutive quarterly LDAR inspections. If the percentage of leaking components is higher than 2.0% in any inspection, a quarterly LDAR inspection interval must be resumed or maintained.

- (c) The detection devices must be operated and maintained in accordance with manufacturer-recommended procedures, as required by the test method, or a Department-approved method.
- (d) A leak is defined as:
 - (i) Any positive indication, whether audible, visual, or odorous, determined during an AVO inspection;
 - (ii) Any visible emissions detected by an OGI camera calibrated according to 40 CFR § 60.18 and a detection sensitivity level of 60 grams/hour; or
 - (iii) A concentration of 500 ppm calibrated as methane or greater detected by an instrument reading.
- (e) For quarterly inspections using a gas leak detector in accordance with 40 CFR Part 60, Appendix A-7, Method 21, the owner or operator may choose to adjust the detection instrument readings to account for the background organic concentration level as determined according to the procedures in Section 8.3.2.
- (f) Any leak detected from a fugitive emission component shall be repaired by the owner or operator of the facility as expeditiously as practicable. A first attempt at repair must be attempted within 5 calendar days of detection, and repair must be completed no later than 15 calendar days after the leak is detected unless:
 - (i) The owner or operator must purchase parts, in which case the repair must be completed no later than 10 calendar days after the receipt of the purchased parts; or
 - (ii) The repair or replacement is technically infeasible, would require a vent blowdown, a well shutdown or well shut-in, or would be unsafe to repair during operation of the unit, the repair or replacement must be completed during the next scheduled well shutdown, well shut-in, after a planned vent blowdown or within 2 years, whichever is earlier.
- (g) Once a fugitive emission component has been repaired or replaced, the owner or operator must resurvey the component as soon as practicable, but no later than 30 calendar days after the leak is repaired.
 - (i) For repairs that cannot be made during the monitoring survey when the leak is initially found, either a digital photograph must be taken of the component or the component must be tagged for identification purposes.
 - (ii) A leak is considered repaired if:
 - (A) There are no detectable emissions consistent with Section 8.3.2 of 40 CFR Part 60, Appendix A-7, Method 21;
 - (B) A leak concentration of less than 500 ppm as methane is detected when the gas leak detector probe inlet is placed at the surface of the component;
 - (C) There is no visible leak image when using an OGI camera calibrated at a detection sensitivity level of 60 grams/hour; or
 - (D) There is no bubbling at the leak interface using a soap solution bubble test specified in Section 8.3.3 of 40 CFR Part 60, Appendix A-7, Method 21.
- (h) The Department determined that the VOC and methane emissions remaining after the implementation of BAT requirements, including LDAR, are of minor significance with regard to causing air pollution, and will not, on their own, be preventing or interfering with the attainment or maintenance of an ambient air quality standard.

2. Recordkeeping Requirements

For fugitive emissions components, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

- (a) The fugitive emissions monitoring plan in accordance with 40 CFR § 60.5397a(b) through (d).
- (b) Records of each monitoring survey which must include:
 - (i) The facility name and location;
 - (ii) The GP-5A authorization number;

- (iii) The date, start time, and end time of the survey;
- (iv) The name of the operator(s) performing the survey;
- (v) The monitoring instrument used;
- (vi) The ambient temperature, sky conditions, and maximum wind speed at the time of the survey;
- (vii) Any deviations from the monitoring plan or a statement that there were none; **and**
- (viii) Documentation of each fugitive emission including:
 - (A) The identification of each component from which fugitive emissions were detected;
 - (B) The instrument reading of each fugitive emissions component that meets the leak definition in Condition 1(d)(iii) of this section;
 - (C) The status of repair of each component including:
 - (1) The repair methods applied in each attempt to repair the component;
 - (2) The tagging or digital photographing of each component not repaired during the monitoring survey in which the fugitive emissions were discovered;
 - (3) The reasons a component was placed on delay of repair;
 - (4) The date of successful repair of the component; **and**
 - (5) The information on the instrumentation or method used to resurvey the component after repair, if it was not completed during the monitoring survey in which the fugitive emissions were discovered.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the records of each monitoring survey conducted during the reporting period shall be included.

The emissions from fugitive emissions components during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION H. NATURAL GAS-DRIVEN PNEUMATIC CONTROLLERS

1. BAT Compliance Requirements

- (a) For pneumatic controllers constructed and authorized to operate on or after August 23, 2011, the owner or operator must meet the applicable requirements of 40 CFR § 60.5390(a) and (c)(1) or 40 CFR § 60.5390a(a) and (c)(1).
- (b) Each controller must be tagged in accordance with 40 CFR § 60.5390(b)(2) and (c)(2) or 40 CFR § 60.5390a(b)(2) and (c)(2) as applicable.

2. Recordkeeping Requirements

For each controller, the owner or operator shall maintain records in accordance with Section A Condition 12 and 40 CFR § 60.5420(c)(4) or § 60.5420a(c)(4) as applicable.

In addition, the emissions calculation for pneumatic controllers must be kept in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each controller during the reporting period shall be done in accordance with 40 CFR § 60.5420(b)(5) or § 60.5420a(b)(5) as applicable.

The emissions from each pneumatic controller in operation during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION I. NATURAL GAS-DRIVEN PNEUMATIC PUMPS

1. BAT Compliance Requirements

- (a) For each natural gas-driven pneumatic diaphragm pump constructed and authorized to operate on or after September 18, 2015, but prior to August 8, 2018, the owner and operator shall meet the applicable requirements of 40 CFR § 60.5365a(h)(2) and § 60.5393a(b) and (e).
- (b) For each natural gas-driven pneumatic pump constructed and authorized to operate on or after August 8, 2018, the owner or operator of a pump with:
 - (i) A methane emission rate of less than 200 tpy, a VOC emission rate of less than 2.7 tpy, a single HAP emission rate less than 0.5 tpy, and a total HAP emission rate less than 1.0 tpy, shall meet the applicable requirements of 40 CFR § 60.5365a(h)(1) and § 60.5393a(a) and (e).
 - (ii) A methane emission rate of 200 tpy or greater, a VOC emission rate of 2.7 tpy or greater, a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, shall route all vapor through a closed vent system to a control device that reduces methane, VOC, and HAP emissions by 95% or more by meeting the applicable requirements of Section J.

2. Recordkeeping Requirements

For each natural gas-driven pneumatic diaphragm pump, the owner or operator shall maintain the following records in accordance with Section A Condition 12 and 40 CFR § 5420a(c)(16) as applicable.

- (a) The location, date of installation, and manufacturer's specifications for each natural gas-driven pneumatic diaphragm pump.
- (b) The emissions calculation for each natural gas-driven pneumatic diaphragm pump must be kept in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

The emissions from each natural gas-driven pneumatic diaphragm pump in operation during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION J. ENCLOSED FLARES AND OTHER EMISSION CONTROL DEVICES

1. BAT Compliance Requirements

- (a) *Enclosed Flares and Other Enclosed Combustion Control Devices.*
 - (i) The owner or operator of an enclosed flare or other enclosed combustion control device shall meet the requirements of 40 CFR § 60.5412(d)(1) and § 60.5415(e) or 40 CFR § 60.5412a(d)(1) and § 60.5415a(e) as applicable. The Department may allow open flares at remote locations and for infrequent operations, provided the flare is installed and operated consistent with 40 CFR § 60.18.
 - (ii) The owner or operator must conduct a performance test in accordance with Condition 4 within 180 days of initial startup of the affected facility unless:
 - (A) The combustion control device is a manufacturer-tested model tested in accordance with 40 CFR § 60.5413(d) or § 60.5413a(d);
 - (B) A performance test conducted on a device of the same make and model in similar service at another facility within the Commonwealth approved by the Department may be used to satisfy this requirement;
 - (iii) The owner or operator must conduct performance tests in accordance with Condition 4 within 180 days of each reauthorization unless:
 - (A) The combustion control device is a manufacturer-tested model tested in accordance with 40 CFR § 60.5413(d) or § 60.5413a(d);
 - (B) A performance test conducted on a device of the same make and model in similar service at another facility within the Commonwealth approved by the Department may be used to satisfy this requirement;

- (C) The Department uses EPA's National Stack Testing Guidance for stack test waivers; or
- (D) The combustion control device established a correlation between the outlet TOC performance level and the firebox or combustion chamber temperature during the initial performance test.
- (iv) The owner or operator of any combustion control device that is a manufacturer-tested model shall meet the requirements of 40 CFR § 60.5413(e) or § 60.5413a(e) as applicable.
- (b) *Vapor Recovery Devices.*
 - (i) The owner or operator of a vapor recovery device shall meet the requirements of 40 CFR § 60.5412(d)(2) and § 60.5415(e) or 40 CFR § 60.5412a(d)(2) and § 60.5415a(e) as applicable.
 - (ii) The owner or operator shall conduct a performance test in accordance with Condition 4 and 40 CFR § 60.5413(b)(5) or § 60.5413a(b)(5) as applicable.
 - (iii) The owner or operator of any vapor recovery device shall conduct a monthly AVO inspection in accordance with 40 CFR § 60.5417(h)(2) or § 60.5417a(h)(2) as applicable.
 - (iv) If the vapor recovery device is a carbon adsorption unit, the owner or operator shall meet the requirements of 40 CFR § 60.5412(c) or § 60.5412a(c) as applicable.
- (c) *External Floating Roof.*
 - (i) An external floating roof shall meet the requirements of 40 CFR § 60.112b(a)(2) and 25 Pa. Code § 129.56(b) as applicable.
 - (ii) Perform a gap measurement test in accordance with 40 CFR § 60.113b for mechanical shoe or liquid-mounted primary seals.
 - (iii) Perform a gap measurement test in accordance with 25 Pa. Code § 129.56(b)(iii) for a vapor-mounted primary seal.
- (d) *Internal Floating Roof.*
 - (i) An internal floating roof shall meet the requirements of 40 CFR § 60.112b(a)(1) and 25 Pa. Code § 129.56(c) as applicable.
 - (ii) Visually inspect the internal floating roof, primary seal, and secondary seal (if equipped) in accordance with 40 CFR § 60.113b(a).
- (e) *Covers.*
 - (i) The cover and all openings on the cover shall meet the requirements of 40 CFR § 60.5411(b) and § 60.5416(a)(3) or 40 CFR § 60.5411a(b) and § 60.5416a(a)(3) as applicable.
 - (ii) The owner or operator shall conduct AVO inspections for defects that could result in air emissions in accordance with Section G Condition 1(a). Defects include, but are not limited to, visible cracks, holes, or gaps in the cover or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices.
 - (iii) Any defect or leak detected shall be repaired in accordance with Section G Condition 1(f) and (g).
- (f) *Closed Vent Systems.*
 - (i) The owner or operator shall conduct an assessment in accordance with 40 CFR § 60.5411a(d), if applicable.
 - (ii) The owner or operator shall design and operate the closed vent system with no detectable emissions, as determined in accordance with 40 CFR § 60.5411(a) and (c) and § 60.5416(a) through (c) or 40 CFR § 60.5411a(a) and (c) and § 60.5416a(a) through (c) as applicable.
 - (iii) The owner or operator shall conduct AVO inspections for defects that could result in air emissions in accordance with Section G Condition 1(a). Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; and broken or missing caps or other closure devices.
 - (iv) Any defect or leak detected shall be repaired in accordance with Section G Condition 1(f) and (g).

2. Recordkeeping Requirements

For each control device, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

- (a) *Enclosed Flares and Other Enclosed Combustion Control Devices.*
 - (i) For non-manufacturer tested models, the owner or operator must maintain records in accordance with 40 CFR § 60.5420(c)(13) and (14) or § 60.5420a(c)(13) and (14) as applicable.
 - (ii) For manufacturer tested models the owner or operator must maintain records in accordance with 40 CFR § 60.5413(d)(12) and (e) or § 60.5413a(d)(12) and (e) as applicable.
 - (iii) The summary for each complete test report described in Section A Condition 14(i) conducted, **if applicable.**
- (b) *Vapor Recovery Devices.*
 - (i) The owner or operator must maintain records in accordance with 40 CFR § 60.5420(c)(12) through (14) or § 60.5420a(c)(12) through (14) as applicable.
 - (ii) The design analysis in accordance with 40 CFR § 60.5413(c) or § 60.5413a(c), as applicable.
 - (iii) The summary for each complete test report described in Section A Condition 14(i) conducted, **if applicable.**
- (c) *External Floating Roof.*
 - (i) The owner or operator must maintain records in accordance with 40 CFR §§ 60.115b and 60.116b as applicable; and
 - (ii) The owner or operator must maintain records in accordance with 25 Pa. Code § 129.56(f)(3) and (g), **if applicable.**
- (d) *Internal Floating Roof.*
 - (i) The owner or operator must maintain records in accordance with 40 CFR §§ 60.115b and 60.116b as applicable; and
 - (ii) The owner or operator must maintain records in accordance with 25 Pa. Code § 129.56(f)(3) and (g), **if applicable.**
- (e) *Covers.*
 - (i) The owner or operator must maintain records in accordance with Section G Condition 2(b).
- (f) *Closed Vent Systems.*
 - (i) The owner or operator must maintain records in accordance with Section G Condition 2(b).
 - (ii) The owner or operator must maintain records in accordance with 40 CFR § 60.5420(c)(8) and (9).
 - (iii) The owner or operator must maintain records of the assessment, including the engineer's certification, in accordance with 40 CFR § 60.5420a(c)(17), **if applicable.**

3. Reporting Requirements

In the required annual report of Section A Condition 13(c), the information about each control device in operation during the reporting period shall be done in accordance with 40 CFR § 60.5420(b) or § 60.5420a(b) as applicable.

4. Control Device Performance Testing Requirements

- (a) When conducting a performance test, the owner or operator must submit the test protocol described in Section A. Condition 14(f) for review and approval. The owner or operator should conduct the following test procedures. Conduct three test runs of at least one-hour duration while operating the control device within 5% of required operating temperature.

- (b) Select the sampling port location and the number and location of traverse points at the exhaust using 40 CFR Part 60, Appendix A-1, Method 1 or 1A depending on stack diameter.
 - (i) If demonstrating compliance with a percent reduction requirement, sampling sites must be located at the inlet of the first control device and the outlet of the final control device; or
 - (ii) If demonstrating compliance with an outlet concentration requirement, the sampling site must be located at the outlet of the control device.
- (c) Determine the effluent characteristics including:
 - (i) The flow velocity, stack temperature, static pressure, and barometric pressure using 40 CFR Part 60, Appendix A-1, Method 2 or 2C depending on stack diameter;
 - (ii) The gas density using 40 CFR Part 60, Appendix A-2, Method 3A; and
 - (iii) The moisture content using 40 CFR Part 60, Appendix A-3, Method 4.
- (d) To demonstrate compliance with (b)(i), use 40 CFR Part 60, Appendix A-7, Method 25A to determine the Total Organic Compounds (TOC) and then convert to dry basis using the moisture content from (c)(iii) above and calculate the inlet and outlet mass rates as propane and the percent reduction.
- (e) To demonstrate compliance with (b)(ii), use 40 CFR Part 60, Appendix A-7, Method 25A to determine the TOC and 40 CFR Part 60, Appendix A-6, Method 18 to determine the methane and ethane concentration, and then correct the TOC concentration, minus methane and ethane, for percent oxygen from (c)(ii) above.

5. Control Device Periodic Monitoring Requirements

The owner or operator that installs a CPMS must install, operate, and maintain the CPMS according to 40 CFR § 60.5415 and § 60.5417 or 40 CFR § 60.5415a and § 60.5417a as applicable.

SECTION K. PIGGING OPERATIONS

1. BAT Compliance Requirements

- (a) The owner or operator that conducts pigging operations shall employ best management practices to minimize the liquids present in the pig receiver chamber and to minimize emissions from the pig receiver chamber including, but not limited to, installing liquids ramps, installing liquids drain, routing high-pressure chambers to a low-pressure line or vessel, using ball valve type chambers, or using multiple pig chambers. The selection of the appropriate best management practices must be documented in the application.
- (b) For pigging operations with a methane emission rate of 200 tpy or greater, or a VOC emission rate of 2.7 tpy or greater, or a single HAP emission rate of 0.5 tpy or greater, or a total HAP emission rate of 1.0 tpy or greater, after employing best management practices, the owner or operator shall control methane, VOC, and HAP emissions from all pigging operations by at least 95% with a condenser, flare, thermal oxidizer, vapor recovery unit, or other air cleaning device, or any alternative method approved by the Department that meets the applicable requirements in Section J.

2. Recordkeeping Requirements

For each pigging operation, the owner or operator shall maintain the following records in accordance with Section A Condition 12, including information on:

- (a) The identification, location, and date of construction of each pig launcher or receiver;
- (b) Records of each pigging operation including the identification of the pig chamber used, the date and time of the pigging operation, and the type and volume of liquids cleared; and
- (c) The emissions calculation for each pig chamber, using the Department's spreadsheet found at <http://files.dep.state.pa.us/> or other equivalent method.

3. Reporting Requirements

The emissions from each pigging operation conducted during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

SECTION L. WELLBORE LIQUIDS UNLOADING OPERATIONS

1. BAT Compliance Requirements

The owner or operator that conducts wellbore liquids unloading operations shall use best management practices including, but not limited to, plunger lift systems, soaping, swabbing, unless venting is necessary for safety to mitigate emissions during liquids unloading activities. In all cases, where technically feasible and safe, the owner or operator shall direct the gas generated during liquids unloading to a control device, a gas production line or existing separator or storage vessel which is controlled. The selection of the appropriate best management practices must be documented in the application.

2. Recordkeeping Requirements

For each well, the owner or operator shall maintain records of each unloading operation that results in emissions to the atmosphere in accordance with Section A Condition 12 containing the following information:

- (a) The US Well number and location of the well;
- (b) The date and time of each wellbore liquids unloading operation;
- (c) The wellbore liquids unloading technique used during each unloading operation;
- (d) The disposition of the associated gas from each wellbore liquids unloading operation;
- (e) The duration of the wellbore liquids unloading operation; and
- (f) The emissions calculation for each wellbore liquids unloading operation in accordance with 25 Pa. Code § 135.5.

3. Reporting Requirements

The emissions from each wellbore liquids unloading operation conducted during the reporting period must be included in the emissions inventory report of Section A Condition 13(d).

Issued by: _____
Krishnan Ramamurthy
Director
Bureau of Air Quality

Date Issued: _____

Date Effective: _____

Air Quality Control Commission

CONTROL OF OZONE VIA OZONE PRECURSORS AND CONTROL OF HYDROCARBONS VIA OIL AND GAS EMISSIONS (EMISSIONS OF VOLATILE ORGANIC COMPOUNDS AND NITROGEN OXIDES)

[Editor's Notes follow the text of the rules at the end of this CCR Document.]

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PART F	Statements of Basis, Specific Statutory Authority and Purpose

Pursuant to Colorado Revised Statutes Section 24-4-103 (12.5), materials incorporated by reference are available for public inspection during normal business hours, or copies may be obtained at a reasonable cost from the Air Quality Control Commission (the Commission), 4300 Cherry Creek Drive South, Denver, Colorado 80246-1530. The material incorporated by reference is also available through the United States Government Printing Office, online at www.govinfo.gov. Materials incorporated by reference are those editions in existence as of the date indicated and do not include any later amendments.

PART A Applicability and General Provisions

I. Applicability

I.A.

I.A.1. The provisions of this regulation shall apply as follows:

I.A.1.a. All provisions of this regulation apply to the Denver 1-hour ozone attainment/maintenance area, to any nonattainment area for the 1-hour ozone standard, and to the 8-hour Ozone Control Area.

I.A.1.b. (State Only) All provisions of this regulation apply to any ozone nonattainment area, which includes areas designated nonattainment for either the 1-hour or 8-hour ozone standard, unless otherwise specified in Section I.A.1.c. Colorado's ozone nonattainment or attainment maintenance area maps and chronologies of attainment status are identified in Appendix A of this regulation.

I.A.1.c. The provisions of Part B, Sections III., IV.B.1. and 2., V.C., and Part D, Sections II., III., IV., and V. apply statewide. The provisions of Part D, Sections II., III., and any other sections marked by (State Only) are not federally enforceable, unless otherwise identified.

I.A.2. REPEALED

I.A.3. REPEALED

I.B. Sources

I.B.1. New Sources

I.B.1.a. New sources, defined as any sources which either (1) submit a complete permit application on or after October 30, 1989, or (2) if no permit is required, commence operation on or after October 30, 1989, must comply with the provisions of this regulation upon commencement of operation.

I.B.1.b. (State Only) New sources are any sources which commenced construction on or after the date on which the area is first designated as being in nonattainment for ozone and are located in that area, or, if located in the 1-hour ozone nonattainment or attainment maintenance area, by October 30, 1989. New sources shall comply with the requirements of this regulation by whichever date comes later:

I.B.1.b.(i) (State Only) October 30, 1989, if they are located in what was previously designated as a 1-hour ozone nonattainment or attainment maintenance area;

I.B.1.b.(ii) (State Only) February 1, 2009, if they are located in an 8-Hour Ozone Control Area and outside of the 1-hour ozone nonattainment or attainment maintenance area; or

I.B.1.b.(iii) (State Only) Upon commencement of operation, if located within an ozone nonattainment or attainment maintenance area.

I.B.1.c. This Section I.B.1. does not apply to oil and gas operations subject to Part D, Section I., stationary and portable engines subject to Part E, Section I.A. through C., or natural gas actuated pneumatic controllers subject to Part D, Section III.

I.B.2. Existing Sources

I.B.2.a. Existing sources are (1) those sources for which a complete permit application was submitted prior to October 30, 1989, or (2) those sources, which commenced operation prior to October 30, 1989.

I.B.2.b. (State Only) Existing sources are those sources which commenced construction prior to the date on which the area is first designated as being in nonattainment for ozone and are located in that area, or, if located in the 1-hour ozone nonattainment or attainment maintenance area, by October 30, 1989.

I.B.2.c. Existing sources shall not be required to comply with requirements of this regulation until on and after October 30, 1991. All existing sources shall comply with the requirements set forth in Exhibit A until October 30, 1991.

I.B.2.d. (State Only) Existing sources shall be required to comply with requirements of this regulation by whichever date comes later:

I.B.2.d.(i) (State Only) October 30, 1989, if they are located in what was previously designated as a 1-hour ozone nonattainment or attainment maintenance area;

I.B.2.d.(ii) (State Only) February 1, 2009, if they are located in an 8-hour Ozone Control Area and outside of the Denver 1-hour ozone nonattainment or attainment maintenance area; or

I.B.2.d.(iii) (State Only) the date on which the area is first designated as being in nonattainment for ozone, if located within that ozone nonattainment or attainment maintenance area.

I.B.2.e. On and after October 30, 1991, all existing sources shall comply with the requirements of this regulation, and Exhibit A shall no longer be applicable.

I.B.2.f. Repealed.

I.B.2.g. Repealed.

I.B.2.h. This Section I.B.2. does not apply to oil and gas operations subject to Part D, Section I., or stationary and portable engines subject to Part E, Section I.A. through C.

I.C. Once a source subject to this regulation exceeds an applicable threshold limit, the requirements of this regulation are irrevocably effective unless the source obtains a federally enforceable permit limiting emissions to levels below the threshold limit by restricting production capacity or hours of operation.

I.D. The owner or operator of a source not required to obtain a permit by provisions of law other than this section may apply for and shall be required to accept a permit as a condition of avoiding RACT requirements. Such permits shall contain only those conditions necessary to ensure the enforcement of the production capacity or hours of operation.

II. General Provisions

II.A. Definitions

- II.A.1. "8-Hour Ozone Control Area" means the Counties of Adams, Arapahoe, Boulder (includes part of Rocky Mountain National Park), Douglas, and Jefferson; the Cities and Counties of Denver and Broomfield; and the following portions of the Counties of Larimer and Weld:
- II.A.1.a. For Larimer County (includes part of Rocky Mountain National Park), that portion of the county that lies south of a line described as follows: Beginning at a point on Larimer County's eastern boundary and Weld County's western boundary intersected by 40 degrees, 42 minutes, and 47.1 seconds north latitude, proceed west to a point defined by the intersection of 40 degrees, 42 minutes, 47.1 seconds north latitude and 105 degrees, 29 minutes, and 40.0 seconds west longitude, thence proceed south on 105 degrees, 29 minutes, 40.0 seconds west longitude to the intersection with 40 degrees, 33 minutes and 17.4 seconds north latitude, thence proceed west on 40 degrees, 33 minutes, 17.4 seconds north latitude until this line intersects Larimer County's western boundary and Grand County's eastern boundary.
- II.A.1.b. For Weld County, that portion of the county that lies south of a line described as follows: Beginning at a point on Weld County's eastern boundary and Logan County's western boundary intersected by 40 degrees, 42 minutes, 47.1 seconds north latitude, proceed west on 40 degrees, 42 minutes, 47.1 seconds north latitude until this line intersects Weld County's western boundary and Larimer County's eastern boundary.
- II.A.2. "Denver 1-Hour Ozone Attainment/Maintenance Area" means the Counties of Jefferson and Douglas, the Cities and Counties of Denver and Broomfield, Boulder County (excluding Rocky Mountain National Park), Adams County west of Kiowa Creek, and Arapahoe County west of Kiowa Creek.
- II.A.3. "Capture System" means the equipment used to contain, capture, or transport a pollutant to a control device.
- II.A.4. "Capture System Efficiency (vapor gathering system efficiency)" means the percent by weight of VOC emitted by an operation subject to this regulation, which is captured by the capture system and sent to the control device; i.e., $(\text{mass flow of VOC captured})/(\text{mass flow of VOC emitted by the operation}) \times 100\%$.
- II.A.5. "Carbon Adsorption System" means a device containing adsorbent material, an inlet and outlet for exhaust gases and a system to regenerate the saturated adsorbent.
- II.A.6. "Condenser" means any heat transfer device used to liquefy vapors by removing their latent heats of vaporization. Such devices include, but are not limited to, shell and tube, coil, surface, or contact condensers.
- II.A.7. "Control Device" means a carbon adsorber, refrigeration system, condenser, flare, firebox or other device, which will reduce the concentration of VOC in a gas stream by adsorption, combustion, condensation, or other means of removal.
- II.A.8. "Control Device Efficiency" means the percent removal by weight of VOC by a control device; i.e., $(\text{mass flow of VOC into control device} - \text{mass flow of VOC out of control device})/(\text{mass flow of VOC into control device}) \times 100\%$.

- II.A.9. "Gasoline" means a petroleum distillate having a Reid vapor pressure between 208 and 1040 torr (4-20 psi), which is used as fuel for internal combustion engines.
- II.A.10. "Highly Volatile Organic Compound" is defined as a Volatile Organic Compound or mixture of such compounds with a true vapor pressure in excess of 570 torr (11 psia) at 20 C.
- II.A.11. "Organic Material" means a chemical compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate.
- II.A.12. (State Only) "Ozone Nonattainment Area" means any area designated as not in attainment with the ozone National Ambient Air Quality Standard as determined by the Environmental Protection Agency.
- II.A.13. "Petroleum Refinery" means any facility engaged in producing gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt, or other products through distillation of petroleum or through redistillation, cracking, rearrangement or reforming of unfinished petroleum derivatives.
- II.A.14. "Reid Vapor Pressure" means the absolute vapor pressure of volatile crude oil and volatile nonviscous petroleum liquids except liquefied petroleum gases as determined by the American Society for Testing and Materials, Part 17, 1973, D-323-72 (Reapproved 1977).
- II.A.15. "True Vapor Pressure" means the equilibrium partial pressure exerted by petroleum (or other) liquid. This may be determined by the methods described in American Petroleum Institute Bulletin 2517, "Evaporation Loss from Floating Roof Tanks," 1962.
- II.A.16. "Vapor Recovery System" means a system that prevents release to the atmosphere of organic compounds emitted during the operation of any transfer, storage, or processing equipment.
- II.A.17. "Volatile Organic Compound (VOC)" means any compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric photochemical reactions, except those listed in Section II.B. as having negligible photochemical reactivity. VOC may be measured by a reference method, an equivalent method, an alternative method, or by procedures specified under 40 CFR Part 60 (September 14, 1989). A reference method, an equivalent method, or an alternative method, however, may also measure nonreactive organic compounds. In such cases, an owner or operator may exclude the compounds listed in Section II.B. when determining compliance with a standard if the amount of such compounds is accurately quantified, and such exclusion is approved by the Division. As a precondition to excluding such compounds as VOC, or at any time thereafter, the Division may require an owner or operator to provide monitoring or testing methods and results demonstrating, to the satisfaction of the Division, the amount of negligible-reactive compounds in the source's emissions.

II.B. Exemptions

Emissions of the organic compounds listed as having negligible photochemical reactivity in the common provisions definition of Negligibly Reactive Volatile Organic Compound are exempt from the provisions of this regulation. However, the hydrocarbon threshold in Part D, Section I.L. and natural gas emissions standards in Part D, Sections III.C.1. and III.C.2. are used as indicators for the volatile organic compound emission reduction measures in Part D, Sections I.L., III.C.1., and III.C.2., and are enforceable provisions of this regulation.

(State Only) Notwithstanding the foregoing exemption, hydrocarbon emissions from oil and gas operations, including methane and ethane, are subject to this regulation as set forth in Part D.

II.C. General Emission Limitation

II.C.1. Existing Sources (State Only: Located in any Ozone Nonattainment Area or Attainment Maintenance Area)

II.C.1.a. All existing sources shall comply with the requirements set forth in this regulation.

- II.C.1.a.(i) Existing sources of VOC which are not subject to specific emission limitations set forth in this regulation, and which have the potential to emit 100 tons per year or more of VOC, shall utilize Reasonably Available Control Technology (RACT).
- II.C.1.a.(ii) The potential to emit of such sources shall be based on design capacity or maximum production rate, whichever is greater, 8,760 hours/year operation, and before add-on controls.
- II.C.1.a.(iii) Owners or operators of such sources with potential emissions of 100 tons per year or more, but with actual emissions less than 100 tons per year may obtain a federally enforceable permit limiting emissions to actual rates by restricting production capacity or hours of operation, thus avoiding RACT requirements.

The owner or operator of a source not required to obtain a permit by provisions of law other than this section may apply for and shall be required to accept a permit as a condition of avoiding RACT requirements. Such permits shall contain only those conditions necessary to ensure the enforcement of the production capacity or hours of operation.

- II.C.1.a.(iv) Such sources with potential emissions of 100 tons per year or more but with actual emissions of less than 50 tons per year, on a rolling 12-month total, may avoid RACT and permit requirements if the following requirements are met:
 - II.C.1.a.(iv)(A) The owner or operator shall submit revised Air Pollutant Emission Notices (APENs) by April 1 of each year, which demonstrate that the 50 tons per year threshold has not been exceeded.

- II.C.1.a.(iv)(B) The owner or operator shall maintain records on site which include monthly VOC use and monthly VOC emissions. The records shall include calculation of total emissions for each rolling 12-month period. The records shall be made available to the Division for inspection upon request.
- II.C.1.a.(v) (State Only) Existing sources that are modified – undergo any physical change, or changed in the method of operation of a stationary source which increase VOC or NOx emissions – on or after March 30, 2008, shall utilize RACT control technologies pursuant to Regulation Number 7 and Regulation Number 3, Part B, Section III.D.2. upon recommencing operation.
- II.C.1.b. Provided however, that no existing source of VOC emissions employing emission controls on or within the six-month period preceding the effective date of this regulation may reduce its level of control of VOC emissions below that level of control actually achieved, even though such source may otherwise be subject to less stringent control requirements, except that no existing source shall be required to control emissions to an extent greater than that level of control which RACT would achieve.
- II.C.1.c. (State Only) Existing sources with potential emissions equal to or greater than 100 tons per year of volatile organic compound emissions shall submit a permit modification application that includes a revised APEN (or APENs) and a RACT analysis, to the Division, as follows:
 - II.C.1.c.(i) (State Only) By October 30, 1991 if located in what was previously designated as the Denver 1-hour ozone nonattainment or attainment maintenance area; or
 - II.C.1.c.(ii) (State Only) By April 30, 2009 or within one year after the date on which the area is first designated as being in nonattainment for ozone, whichever comes later, if they are located in the 8-hour Ozone Control Area and outside of the Denver 1-hour ozone nonattainment or attainment maintenance area.
- II.C.1.d. (State Only) Existing sources shall utilize RACT pursuant to Regulation Number 7 and Regulation Number 3, Part B, Section III.D.2. by whichever date comes later:
 - II.C.1.d.(i) (State Only) October 30, 1991, if they are located in what was previously designated as the Denver 1-hour ozone nonattainment or attainment maintenance area;
 - II.C.1.d.(ii) (State Only) November 21, 2011, if they are located in the 8-hour Ozone Control Area, and outside of the Denver 1-hour ozone nonattainment or attainment maintenance area;
 - II.C.1.d.(iii) (State Only) Three years after the date on which the area is first designated as being in nonattainment for ozone; or

- II.C.1.d.(iv) (State Only) Two years after Division determination of case-by-case RACT pursuant to this Section II.C.1. The Division shall be deemed to have approved the RACT analysis for purposes of this Section II.C.1.d.(iv) if it does not object after eighteen months from having received a complete permit application.

II.C.2. New Sources

All new sources shall utilize controls representing RACT, pursuant to Regulation Number 7 and Regulation Number 3, Part B, Section III.D., upon commencement of operation.

II.D. Alternative Control Plans and Test Methods

- II.D.1. Sources subject to specific requirements of this regulation shall submit for approval as a revision to the State Implementation Plan:

II.D.1.a. Any alternative emission control plan or compliance method other than control options specifically allowed in the applicable regulation. Such alternative control plans shall provide control equal to or greater than the emission control or reduction required by the regulation, unless the source contends that the control level required by the regulation does not represent RACT for their specific source.

II.D.1.b. Any alternative test method or procedure not specifically allowed in the applicable regulation.

- II.D.2. No alternative submitted pursuant to this Section II.D. is effective until the alternative is approved as a revision to the State Implementation Plan.

II.E. REPEALED

II.F. Provisions for Specific Processes

- II.F.1. The Gates Rubber Company Provision – REPEALED

Appendix A Colorado Ozone Nonattainment or Attainment Maintenance Areas

I. Chronology of Attainment Status

Denver Metropolitan Area Only

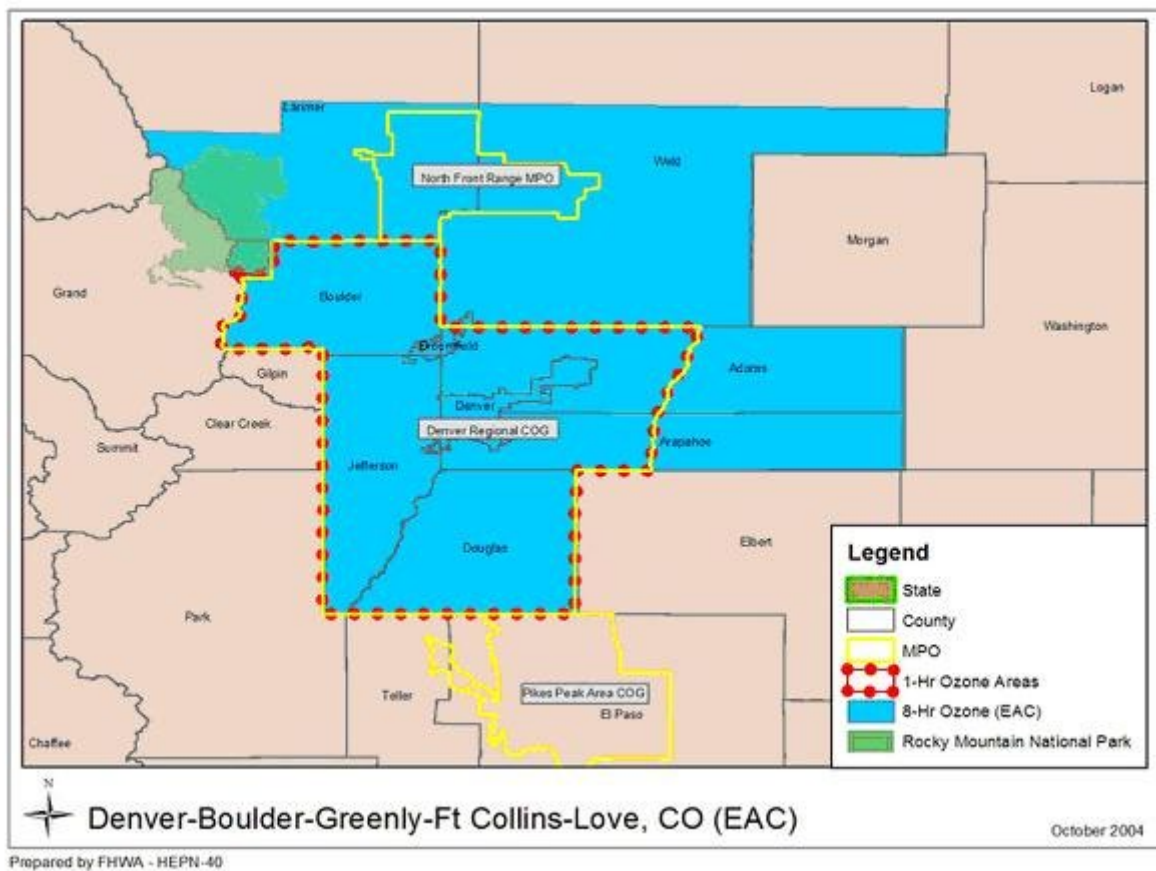
1978	Denver 1-hour Ozone Nonattainment Area designation first becomes effective in 7-county Denver Metropolitan Area
10/11/01	Denver 1-hour Ozone Attainment Maintenance Area designation replaces non-attainment designation and becomes effective in 7-county Denver Metropolitan Area
9/2/05	1-hour Ozone National Ambient Air Quality Standard is Revoked in Colorado except for the Denver 1-hour Ozone Attainment Maintenance Area.

Denver Metropolitan Area and North Front Range

- 10/11/01 1-hour attainment maintenance area replaces non-attainment designation for the Denver Metro Area/North Front Range Area
- 4/15/04 EPA designates the Denver Metro Area/North Front Range region as an 8-hour ozone non-attainment area, designation deferred due to the implementation of the Early Action Compact
- 11/20/07 Denver 8-hour ozone non-attainment designation becomes effective in 9 county Denver Metropolitan Area

II. Maps

Denver Metropolitan Area and North Front Range



PART B Storage, Transfer, and Disposal of Volatile Organic Compounds and Petroleum Liquids and Petroleum Processing and Refining

I. General Requirements for Storage and Transfer of Volatile Organic Compounds

I.A. Maintenance and Operation of Storage Tanks and Related Equipment

All storage tank gauging devices, anti-rotation devices, accesses, seals, hatches, roof drainage systems, support structures, and pressure relief valves shall be maintained and operated to prevent detectable vapor loss except when opened, actuated, or used for necessary and proper activities (e.g. maintenance). Such opening, actuation, or use shall be limited so as to minimize vapor loss.

Detectable vapor loss shall be determined visually, by touch, by presence of odor, or using a portable hydrocarbon analyzer. When an analyzer is used, detectable vapor loss means a VOC concentration exceeding 10,000 ppm. Testing and monitoring shall be conducted as in Part B, Section VI.C.3.

I.B. Transfer (excluding Petroleum Liquids)

Except as otherwise provided in this regulation, all volatile organic compounds transferred to any tank, container, or vehicle compartment with a capacity exceeding 212 liters (56 gallons), shall be transferred using submerged or bottom filling equipment. For top loading, the fill tube shall reach within six inches of the bottom of the tank compartment. For bottom-fill operations, the inlet shall be flush with the tank bottom.

I.C. Beer production and associated beer container storage and transfer operations involving volatile organic compounds with a true vapor pressure of less than 1.5 psia actual conditions are exempt from the provisions of Section I.B.

II. Storage of Highly Volatile Organic Compounds

II.A. Highly volatile organic compounds shall be stored:

II.A.1. In a pressure tank which is at all times capable of maintaining working pressures sufficient to prevent vapor loss to the ambient air; or

II.A.2. With methods and/or equipment approved by the Division in writing pursuant to the request of the person owning or operating the storage facility.

II.B. Vapor loss shall be determined visually, by presence of frost or condensation at the point of leakage, or using a portable hydrocarbon analyzer. When an analyzer is used, vapor loss means a VOC concentration exceeding 10,000 ppm and testing and monitoring procedures shall be conducted as in Part B, Section VI.C.3.

III. Disposal of Volatile Organic Compounds

III.A. No person shall dispose of volatile organic compounds by evaporation or spillage unless RACT is utilized.

III.B. No owner or operator of a bulk gasoline terminal, bulk gasoline plant, or gasoline dispensing facility as defined in Part B, Sections IV.C.2., IV.C.3. and VII.A.3., shall permit gasoline to be intentionally spilled, discarded in sewers, stored in open containers, or disposed of in any other manner that would result in evaporation.

IV. Storage and Transfer of Petroleum Liquid

IV.A. General Requirements

IV.A.1. No person shall build, install, or permit the building or installation of any rotating pump or compressor handling any type of petroleum liquid unless said pump or compressor is equipped with mechanical seals or other equipment of equal efficiency. If reciprocating-type pumps and compressors are used, they shall be equipped with packing glands properly installed, in good working order, and properly maintained so that no detectable emissions occur from the drain recovery systems.

IV.A.2. Definitions

For the purpose of this section, the following definitions apply:

- IV.A.2.a. Repealed.
- IV.A.2.b. "Crude Oil" means a naturally occurring mixture which consists of hydrocarbons, sulfur, nitrogen or oxygen derivatives of hydrocarbons, and which is a liquid at standard conditions.
- IV.A.2.c. "Custody Transfer" means the transfer of produced crude oil and/or condensate, after processing and/or treating in the producing operations, from storage tanks or automatic transfer facilities to pipelines or any other forms of transportation.
- IV.A.2.d. "EFR Tank" means a storage vessel having an external floating roof.
- IV.A.2.e. "External Floating Roof" means a storage vessel cover in an open top tank consisting of a double deck or pontoon single deck which rests upon and is supported by the petroleum liquid being contained and is equipped with a closure seal or seals to close the space between the roof edge and tank wall.
- IV.A.2.f. "Liquid-Mounted Seal" means a primary seal mounted in continuous contact with the contained liquid and which occupies an annular space between the inner tank wall and the perimeter of the floating roof.
- IV.A.2.g. "Petroleum Liquid" means crude oil, condensate and any finished or intermediate product manufactured or extracted in a petroleum refinery.
- IV.A.2.h. "Shoe Seal" means a primary seal employing a metallic band (called a shoe) which is held against the vertical inner-wall of the tank, concentric with the perimeter of the floating roof.
- IV.A.2.i. "Vapor Balance System" means a combination of pipes or hoses that create a closed system between the vapor spaces of an unloading tank and a receiving tank such that vapors displaced from the receiving tank are transferred to the tank being unloaded.

- IV.A.2.j. "Vapor Collection System" means a vapor transport system which uses direct displacement by the gasoline being transferred to force vapors from the vessel being loaded into either a vessel being unloaded or a vapor holding tank.
- IV.A.2.k. "Vapor-Mounted Seal" means a primary seal mounted so there is an annular vapor space underneath the seal. The annular vapor space is bounded by the bottom of the primary seal, the liquid surface, the floating roof, and the tank wall (thus excluding shoe seals).
- IV.A.2.l. "Waxy, Heavy Pour Crude Oil" means a crude oil with a pour point of 10°C (50°F) or higher as determined by the American Society for Testing and Materials Standard D97-66, "Test for Pour Point of Petroleum Oils."

IV.B. Storage of Petroleum Liquid

IV.B.1. Exemptions

- IV.B.1.a. Tanks or other containers used to store the following liquids are exempt from the provisions of Sections IV.B.2. and IV.B.3.:
 - IV.B.1.a.(i) Diesel Fuels 1-D, 2-D, and 4-D as defined in ASTM D975-78.
 - IV.B.1.a.(ii) Fuel Oils #1, #2, #3, #4, and #5, as defined in ASTM D396-78.
 - IV.B.1.a.(iii) Gas Turbine Fuels 1-GT through 4-GT as defined in ASTM D2880-78.
- IV.B.1.b. The following underground storage facilities are exempt from Section IV.B.2.:
 - IV.B.1.b.(i) Underground tanks if the annual sum total of the volume of liquid removed from the tank plus the sum of the volume of liquid added to it does not exceed twice the operational volume of the tank (i.e., a maximum of one turnover per year is allowed).
 - IV.B.1.b.(ii) Subsurface caverns or porous rock reservoirs.
 - IV.B.1.b.(iii) Horizontal underground tanks storing JP-4 Jet Fuel.

IV.B.2. Storage of petroleum liquid in tanks greater than 151,412 liters (40,000 gallons)

- IV.B.2.a. Storage of petroleum liquid in fixed-roof tanks.
 - IV.B.2.a.(i) The owner or operator of a fixed-roof tank used for storage of petroleum liquids which have a true vapor pressure greater than 33.6 torr (0.65 psia) at 20°C (or, alternatively, a Reid vapor pressure greater than 1.30 pounds - (67.2 torr) but not greater than 570 torr (11.0 psia) at 20°C, and which are stored in any tank or other container of more than 151,412 liters (40,000 gallons) shall ensure that the tank at all times meets the following conditions:

- IV.B.2.a.(i)(A) The tank has been equipped with a pontoon-type, or double-deck type, floating roof or an internal floating cover which rests on the surface of the liquid contents and which is equipped with a closure seal or seals to close the space between the edge of the floating roof (or cover) and tank walls; or
- IV.B.2.a.(i)(B) The tank has been equipped with a vapor gathering system capable of collecting the petroleum liquid vapors discharged, together with a vapor recovery or disposal system capable of processing such vapors so as to prevent their emission into the atmosphere.
- IV.B.2.a.(i)(C) Control devices shall meet the applicable requirements, including recordkeeping, of Part C, Sections III.A.3.a., b., c., and e., and III.A.8.a. and b.
- IV.B.2.a.(i)(D) The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 (September 14, 1989) shall be used to determine the efficiency of control devices.
- IV.B.2.a.(i)(E) The owner or operator shall maintain records for at least two years of the type, average monthly storage temperature, and true vapor pressure of all petroleum liquids stored in tanks not equipped with an internal floating roof or cover or other control pursuant to Regulation Number 7, Sections IV.B.2.a.(i)(A) or IV.B.2.a.(i)(B) or Part A, Section II.D.
- IV.B.2.a.(ii) No owner or operator of a fixed-roof tank equipped with an internal floating roof or cover shall permit the use of such tank unless:
 - IV.B.2.a.(ii)(A) The tank is maintained such that there are no visible holes, tears, or other openings in the seal or any seal fabric or materials; and
 - IV.B.2.a.(ii)(B) All openings, except stub drains, are equipped with covers, lids, or seals such that:
 - IV.B.2.a.(ii)(B)(1) The cover, lid, or seal is in the closed position at all times except when in actual use;
 - IV.B.2.a.(ii)(B)(2) Automatic bleeder vents are closed at all times except when the roof is floated off or landed on the roof leg supports; and
 - IV.B.2.a.(ii)(B)(3) Rim vents, if provided, are set to open when the roof is being floated off the roof leg supports or at the manufacturer's recommended setting.

IV.B.2.a.(iii) The operator of a fixed-roof tank equipped with an internal floating roof shall:

IV.B.2.a.(iii)(A) Perform a routine inspection through the tank roof hatches at least once every six months;

IV.B.2.a.(iii)(A)(1) During the routine inspection, the operator shall measure for detectable vapor loss inside the hatch. Detectable vapor loss means a VOC concentration exceeding 10,000 ppm, using a portable hydrocarbon analyzer.

IV.B.2.a.(iii)(B) Perform a complete inspection of the cover and seal whenever the tank is out of service, whenever the routine inspection required in Section IV.B.2.a.(iii)(A) reveals detectable vapor loss, and at least once every ten years, and shall notify the Division in writing before such an inspection.

IV.B.2.a.(iii)(C) Ensure during inspections that there are no visible holes, tears, or other openings in the seal or any seal fabric or materials; that the cover is floating uniformly on or above the liquid surface; that there are no visible defects in the surface of the cover or liquid accumulated on the cover; and that the seal is uniformly in place around the circumference of the cover between the cover and the tank wall. If these items are not met, the owner or operator shall repair the items or empty and remove the storage vessel from service within 45 days. If a failure that is detected during inspections required in this section cannot be repaired within 45 days and if the vessel cannot be emptied within 45 days, a 30-day extension may be requested from the Division in writing. Such a request must document that alternative storage capacity is unavailable and specify a schedule of actions the owner or operator will take that will assure that the items will be repaired or the vessel will be emptied as soon as possible;

IV.B.2.a.(iii)(D) Maintain records for at least two years of the results of all inspections.

IV.B.2.b. Above ground storage tanks used for the storage of petroleum liquid shall have all external surfaces coated with a material which has a reflectivity for solar radiation of 0.7 or more. Methods A or B of ASTM E424 shall be used to determine reflectivity. Alternatively, any untinted white paint may be used which is specified by the manufacturer for such use.

This provision shall not apply to written symbols or logograms applied to the external surface of the container for purposes of identification provided such symbols do not cover more than 20% of the exposed top and side surface area of the container or more than 18.6 square meters (200 square feet), whichever is less.

IV.B.2.c. Seals on External Floating Roof Tanks

IV.B.2.c.(i) General Provisions

IV.B.2.c.(i)(A) Applicability

This section applies to all petroleum liquid storage vessels equipped with external floating roofs, having capacities greater than 150,000 liters (40,000 gallons) that are located in ozone nonattainment areas.

IV.B.2.c.(i)(B) Exemptions

IV.B.2.c.(i)(B)(1) Total Exemption

The following categories of EFR tanks are exempt from the requirement of Section IV.B.2.c., except for the applicable recordkeeping requirements of Section IV.B.2.c.(ii)(C).

IV.B.2.c.(i)(B)(1)(a) EFR tanks which store any material whose true vapor pressure as stored never exceeds 67 torr (1.3 psia).

IV.B.2.c.(i)(B)(1)(b) Tanks less than 1,600,000 liters (10,000 barrels) which are used to store crude oil and condensate prior to custody transfer.

IV.B.2.c.(i)(B)(2) Limited Exemptions

The following are exempt from both secondary seal and secondary seal inspection requirements but shall meet the equipment/procedure provisions in Section IV.B.2.c.(ii)(A)(1), the semi-annual inspection provisions of Section IV.B.2.c.(ii)(B), and the record keeping provisions of Section IV.B.2.c.(ii)(C).

IV.B.2.c.(i)(B)(2)(a) Those tanks storing petroleum liquid between 67 and 207 torr (1.3 to 4.0 psia) maximum true vapor pressure (as stored) which are of welded construction and which have one of the following primary seals:

IV.B.2.c.(i)(B)(2)(a)(I) metallic shoe seal

IV.B.2.c.(i)(B)(2)(a)(II) liquid mounted, resilient seal

IV.B.2.c.(i)(B)(2)(a)(III) liquid mounted, liquid filled seal

IV.B.2.c.(i)(B)(2)(b) Any tank storing waxy, heavy-pour crude oil.

IV.B.2.c.(ii) General Requirements

IV.B.2.c.(ii)(A) An operator of an EFR tank storing petroleum liquids with true vapor pressure (as stored) above 67 torr (1.3 psia) shall equip the tank as follows and observe the following procedures:

IV.B.2.c.(ii)(A)(1) Equipment

IV.B.2.c.(ii)(A)(1)(a) Drains: roof drains which are designed to empty directly into the stored product shall be provided with slotted-membrane fabric covers or equivalent covers which cover at least 90 percent of the area of the opening.

IV.B.2.c.(ii)(A)(1)(b) Openings: except for automatic bleeder vents, rim space vents, and leg sleeves, all openings shall be equipped with:

IV.B.2.c.(ii)(A)(1)(b)(I) Projections into the tank which remain below the liquid surface at all times; and

IV.B.2.c.(ii)(A)(1)(b)(II) Covers, seals, or lids.

IV.B.2.c.(ii)(A)(2) Procedures

IV.B.2.c.(ii)(A)(2)(a) Covers, seals and lids shall be kept closed except when the openings are in actual use.

IV.B.2.c.(ii)(A)(2)(b) Automatic bleeder vents shall be kept closed at all times except when the roof is floated off or landed on roof leg supports.

IV.B.2.c.(ii)(A)(2)(c) Rim vents shall be set to open at the manufacturer's recommended setting or, alternatively, only when the roof is being floated off the leg supports.

IV.B.2.c.(ii)(B) Inspections

The operator of an EFR tank subject to this Section IV.B.2.c. shall:

IV.B.2.c.(ii)(B)(1) Perform routine inspections at least once every six months in order to ensure compliance with Section IV.B.2.c.(ii)(B)(2). The inspections shall include a visual inspection of the secondary seal gap if equipped with a secondary seal.

IV.B.2.c.(ii)(B)(2) Ensure that all seal closure devices meet the following requirements:

IV.B.2.c.(ii)(B)(2)(a) There are no visible holes, tears, or other openings in the seal(s) or seal fabric; and

IV.B.2.c.(ii)(B)(2)(b) The seal(s) are intact and uniformly in place around the circumference of the floating roof and the tank wall.

IV.B.2.c.(ii)(C) Records

IV.B.2.c.(ii)(C)(1) Operators shall:

IV.B.2.c.(ii)(C)(1)(a) Maintain records of the average monthly storage temperature, the Reid vapor pressure of the liquid and the type of liquid stored for all EFR tanks lacking secondary seals and receiving petroleum liquids with a true vapor pressure of 1.0 psi (7.0kPa) or greater; and

IV.B.2.c.(ii)(C)(1)(b) Maintain records of the results of the inspections required herein.

IV.B.2.c.(ii)(C)(2) Copies of all records specified by this Section IV.B.2.c.(ii)(C) shall be retained by the operator for a minimum of two years after the date on which the record was made.

IV.B.2.c.(iii) Secondary Seal Requirements

IV.B.2.c.(iii)(A) General

No owner or operator of an EFR tank (storing petroleum liquids) not specifically exempted in Section IV.B.2.c.(i)(B) shall store that petroleum liquid unless such vessel is equipped with a continuous secondary seal extending from the rim of the floating roof to the tank wall (i.e., a rim-mounted secondary seal).

IV.B.2.c.(iii)(B) Vapor-Mounted Seals

For EFR tanks required to have a secondary seal and which have a vapor-mounted primary seal:

IV.B.2.c.(iii)(B)(1) An annual inspection shall be made of the total gap area between the secondary seal and the wall of the tank in accordance with the method in IV.B.2.c.(iii)(B)(3).

- | | |
|-------------------------|---|
| IV.B.2.c.(iii)(B)(2) | This total gap area shall not exceed 21.2 cm ² /meter diameter (1.0 in ² /ft. diameter). |
| IV.B.2.c.(iii)(B)(3) | Method to determine gap area: |
| IV.B.2.c.(iii)(B)(3)(a) | Physically measure the length and width of all gaps around the entire circumference of the secondary seal in each place where a 0.32 cm (1/8 in.) uniform diameter probe passes freely (without forcing or binding against the seal) between the seal and the tank wall; and, |
| IV.B.2.c.(iii)(B)(3)(b) | Sum the area of the individual gaps. |
- IV.B.3. Storage of petroleum liquid in tanks of or less than 151,412 liters (40,000 gallons) capacity.
- | | |
|---------------|---|
| IV.B.3.a. | Tanks or containers used to store liquids with true vapor pressure at 20°C of less than 78 torr (1.5 psia) or greater than 570 torr (11.0 psia) at 20°C are exempt from the provisions of this Section IV.B.3. |
| IV.B.3.b. | The owner or operator of storage tanks at a gasoline dispensing facility (service station) or other facility not addressed in Sections IV.C.2. or IV.C.3., which receives and stores petroleum liquid, shall not allow the transfer of petroleum liquid from any delivery vessel into any tank unless the tank is equipped with a submerged fill pipe and all vapors displaced from the storage tank are transferred to the delivery vessel being unloaded using a properly maintained, functioning, and leak-tight vapor collection system, as in accordance with applicable provisions of Appendix B and Section VII., if the tank: |
| IV.B.3.b.(i) | Has a rated manufacturer's capacity of 2,082 liters (550 gallons) or more and was installed after November 7, 1973, (except for storage tanks below 550-gallon capacity used exclusively for agricultural use; however, these must have a submerged fill pipe), or |
| IV.B.3.b.(ii) | Has a rated manufacturer's capacity of 7,571 liters (2,000 gallons) or more and was installed before November 7, 1973. |
| IV.B.3.c. | Tanks equipped with a submerged fill pipe shall meet the specifications of Appendix B. |
| IV.B.3.d. | The owner or operator of storage tanks at a gasoline dispensing facility must install and operate one or more of the following |
| IV.B.3.d.(i) | A vapor collection system designed and operated in accordance with a vapor-tight line from the storage tank to delivery vessel. |
| IV.B.3.d.(ii) | A refrigerator-condensation system or equivalent designed to recover at least 90 percent by weight of the organic compounds in the displaced vapor. |

- IV.B.3.e. The owner or operator shall ensure that operating procedures are used so that gasoline cannot be transferred into the tank unless the vapor collection system is installed and operated to ensure the system is leak-tight during gasoline transfer.
- IV.B.3.f. The vapor collection system shall meet the specifications of Appendix B and applicable requirements of Section VII.
- IV.B.3.g. Control devices shall meet the applicable requirements, including recordkeeping, of Part C, Sections I.A.3.a., b., c., and e., and I.A.8.a. and b.
- IV.B.3.h. The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 (September 14, 1989) shall be used to determine the efficiency of control devices.

IV.C. Transfer of Petroleum Liquid

IV.C.1. Exemptions

Transfer operations involving petroleum liquid with true vapor pressures at 20°C of less than 78 torr (1.5 psia) or greater than 570 torr (11.0 psia) shall be exempt from the provisions of this Section IV.C.

IV.C.2. Loading Facilities Classified as Terminals

- IV.C.2.a. A terminal is defined as a petroleum liquid storage and distribution facility that has an average daily throughput of more than 76,000 liters of gasoline (20,000 gallons), which is loaded directly into transport vehicles. A rolling, 30-day average of throughput shall be used to determine the applicability of this Section IV.C.2.
- IV.C.2.b. The owner or operator of a terminal subject to this section shall equip the terminal with proper loading equipment and shall follow the loading procedures listed:
 - IV.C.2.b.(i) Install dry-break loading couplings to prevent petroleum liquid loss during uncoupling from vehicles.
 - IV.C.2.b.(ii) Install a vapor collection and disposal system which gathers vapor transferred from vehicles being loaded. The system shall include devices to prevent the release of vapor from vapor recovery hoses not in use.
 - IV.C.2.b.(iii) Use operating procedures to ensure that petroleum liquid cannot be transferred unless the vapor collection equipment is in use.
 - IV.C.2.b.(iv) Provide for the prevention of overfilling of transport vehicles with loading pump shut-offs, set stop meters, or comparable equipment.
 - IV.C.2.b.(v) Operate all recovery and disposal equipment at a back pressure less than the pressure relief valve setting of transport vehicles.

- IV.C.2.b.(vi) Prevent the release of petroleum liquid on the ground from transport vehicles. Provision shall be made to remove any undelivered petroleum liquid with closed drainage devices.
- IV.C.2.b.(vii) Maintain and operate final recovery and disposal equipment or control devices so as to emit no more than 80 milligrams of volatile organic compounds per liter of gasoline being loaded. Such disposal devices shall be approved by the Division.
- IV.C.2.b.(viii) Prevent loading of petroleum liquid into transport vehicles which do not have valid leak-tight test certification as required in Section IV.D.
- IV.C.2.b.(ix) Follow all control procedures to prevent leaks as specified in Section VII.
- IV.C.2.c. Control devices shall meet the applicable requirements, including recordkeeping of Part C, Sections I.A.3.a., b., c., and e., and I.A.8.a. and b.
- IV.C.2.d. The applicable methods of 40 CFR 60. 503 (September 14, 1989), or EPA reference methods 1 through 4, 25A, and 25B of 40 CFR Part 60 (September 14, 1989) shall be used to determine the efficiency of control devices.
- IV.C.2.e. The method set forth in Appendix A of "Control of Hydrocarbons from Tank Truck Gasoline Loading Terminals" October 1977, EPA-450/2-77-026 shall be used to test emission points other than control devices.

IV.C.3. Loading Facilities Classified as Bulk Plants

- IV.C.3.a. A bulk plant is defined as a petroleum liquid storage and distribution facility that has an average daily throughput of 76,000 liters of gasoline (20,000 gallons) or less, which is loaded directly into transport trucks. (As used herein, "bulk plant" does not include service stations nor separate operations within petroleum liquid distribution facilities which pump only into fuel tanks fueling motor vehicles. Both such operations are regulated by Section IV.B.3.). A rolling 30-day average of throughput shall be used to determine the applicability of this regulation.
- IV.C.3.b. The owner or operator of a bulk storage plant subject to this section shall install a vapor balance system to return vapors to the incoming transport trucks during the filling of tanks controlled under Section IV.B.3. The vapor balance system must be designed and operated in accord with the provisions of Appendix C.)
- IV.C.3.c. The owner or operator of a bulk plant which serves storage tanks which are required to collect and recover vapor as prescribed in Section IV.B.3. shall:
 - IV.C.3.c.(i) Install and operate vapor collection and return equipment on any transport vehicles used to deliver to controlled tanks, and

- IV.C.3.c.(ii) Install and operate vapor collection and return equipment at loading facilities to collect vapors during loading of tank compartments of outbound transport trucks and return these vapors to the bulk plant storage tanks, using a vapor balance system.
- IV.C.3.c.(iii) Assure that transport trucks and loading facilities conform to the applicable provisions of Sections IV.C.2. and IV.C.4.
- IV.C.3.d. The owner or operator of a bulk plant which serves only storage tanks exempted from the provisions of Section IV.B.3.b. by reason of their small size or location in an attainment area shall load outbound transport trucks using equipment that provides for top loading of the petroleum liquid into the vehicle tank compartments through an extended fill tube which reaches within 15.24 cm (6 in.) of the bottom of the tank compartment.
- IV.C.3.e. The owner or operator of a bulk plant subject to this section shall ensure that petroleum liquid cannot be transferred unless the vapor collection equipment is in use.
- IV.C.3.f. The owner or operator of a bulk plant subject to this section shall follow all procedures to prevent leaks as specified in Section VII.

IV.C.4. Transport Vehicles

- IV.C.4.a. Rail cars shall be loaded only at facilities which allow for the following:
 - IV.C.4.a.(i) A submerged fill pipe which reaches within 15.24 cm (6 in.) of the bottom of the tank.
 - IV.C.4.a.(ii) Vapor collection and/or disposal equipment designated and operated to recover vapors displaced during the loading of the rail car.
 - IV.C.4.a.(iii) A vapor-tight seal around the tank car hatch and the loading equipment.
- IV.C.4.b. The owner or operator of petroleum transport trucks which serve locations required to be equipped with vapor recovery equipment shall load only at facilities capable of disposing of collected vapors. The owner or operator shall assure that such vehicles possess the proper equipment and that work practices are followed so that:
 - IV.C.4.b.(i) Dry-break loading and unloading nozzles are used and are compatible with those required at loading facilities.
 - IV.C.4.b.(ii) Vapor recovery hoses are connected at all times during unloading or loading of petroleum distillate.
 - IV.C.4.b.(iii) Transport trailers and vehicle tanks are operated and maintained to prevent detectable hydrocarbon vapor loss during loading, transport and delivery.

IV.C.4.b.(iv) Compartment dome lids are closed and locked during transfers of petroleum liquid. Such lids may be opened for the purpose of certifying the accuracy of a delivery only prior to and after such delivery.

IV.C.4.b.(v) Hoses, couplings, and valves are maintained to prevent dripping, leaking, or other liquid or vapor loss during loading or unloading.

IV.D. Control of Volatile Organic Compound Leaks from Gasoline Transport Trucks

IV.D.1. General Provisions

IV.D.1.a. Applicability

This section is applicable to all gasoline transport trucks equipped for gasoline vapor collection which receive or dispense gasoline at terminals, bulk plants, or gasoline dispensing facilities located in the nonattainment areas.

IV.D.1.b. Definitions

For the purpose of this section, the following definitions apply:

IV.D.1.b.(i) "Gasoline Transport Truck" means a tank truck or tank trailer equipped with a storage tank and used for the transport of gasoline from sources of supply to stationary storage tanks of gasoline dispensing facilities (e.g., service stations), bulk gasoline plants, or gasoline terminals.

IV.D.1.b.(ii) "Vapor Collection System" means a vapor transport system which uses direct displacement by the gasoline being transferred to force vapors from the vessel being loaded into a vessel being unloaded or into a vapor holding tank.

IV.D.2. Provisions for Specific Processes

IV.D.2.a. No terminal operator, when monitoring the gasoline loading operation and no owner or operator of a gasoline transport truck shall allow a gasoline transport truck subject to this Section IV.D. to be filled with a VOC with Reid Vapor Pressure of 4.0 or greater unless the gasoline tank truck:

IV.D.2.a.(i) Is tested annually according to the test procedure in EPA Method 27 (40 CFR Part 60, Appendix A-8) (October 17, 2000). Testing must be completed prior to the onset of the summer ozone season (test October through April). In addition, a visual inspection, as detailed in Section IV.D.3.b. must be performed at least once every six months.

IV.D.2.a.(i)(A) The test must be conducted using a time period (t) for the pressure and vacuum tests of 5 minutes.

IV.D.2.a.(i)(B) The initial pressure (P_i) for the pressure test must be 460 mm H₂O (18 in. H₂O), gauge.

IV.D.2.a.(i)(C) The initial vacuum (V_i) for the vacuum test must be 150 mm H₂O (6 in. H₂O), gauge.

IV.D.2.a.(i)(D) The maximum allowable pressure and vacuum changes must not exceed the values in Table 1.

IV.D.2.a.(i)(E) After completing the tests under Sections IV.D.2.a.(i)(A) through (D), the tank's internal vapor valve must be pressure tested.

IV.D.2.a.(i)(E)(1) Use the procedures in EPA Method 27 (40 CFR Part 60, Appendix A-8) (October 17, 2000) to repressurize the tank to 460 mm H₂O (18 in. H₂O), gauge.

IV.D.2.a.(i)(E)(2) Close the tank's internal vapor valve(s), thereby isolating the vapor return line and manifold from the tank.

IV.D.2.a.(i)(E)(3) Relieve the pressure in the vapor return line to atmospheric pressure, then reseal the line.

IV.D.2.a.(i)(E)(4) After 5 minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable 5-minute pressure increase is 130 mm H₂O (5 in. H₂O).

Table 1 - Allowable Cargo Tank Test Pressure or Vacuum Change		
Cargo tank or compartment capacity, liters (gal)	Annual certification-allowable pressure or vacuum change in 5 minutes, mm H ₂ O (in. H ₂ O)	Allowable pressure change in 5 minutes at any time, mm H ₂ O (in. H ₂ O)
9,464 or more (2,500 or more)	25 (1.0)	64 (2.5)
9,463 to 5,678 (2,499 to 1,500)	38 (1.5)	76 (3.0)
5,679 to 3,785 (1,499 to 1,000)	51 (2.0)	89 (3.5)
3,782 or less (999 or less)	64 (2.5)	102 (4.0)

IV.D.2.a.(ii) Passes a retest within twenty (20) days if it does not meet the criteria of Section IV.D.2.a.(i).

IV.D.2.b. Monitoring

IV.D.2.b.(i) The Division may, at any time, monitor a gasoline tank truck vapor collection system to confirm continued compliance with Section IV.D.2.a.

- IV.D.2.b.(ii) Within fifteen (15) days after an exceedance is detected a tank shall pass a pressure/vacuum test per EPA Method 27 (40 CFR Part 60, Appendix A-8 (October 17, 2000)).

IV.D.3. Testing and Monitoring

- IV.D.3.a. The owner or operator of a gasoline transport truck shall at their own expense, demonstrate compliance with Section IV.D.2, by methods of EPA Method 27 (40 CFR Part 60, Appendix A-8) (October 17, 2000). All tests shall be made by, or under the direction of, a person qualified by training and/or experience in the field of air pollution testing or gasoline transport truck maintenance.
- IV.D.3.b. The owner or operator of a gasoline transport truck must conduct a visual inspection of the gasoline transport truck at least once every six months. The entire tank, including domes, dome vents, cargo tank, piping, hose connections, hoses and delivery elbows, must be inspected for wear, damage, or misadjustment that could be a potential leak source. Inspect all rubber fittings except those in piping which are not accessible. Any part found to be defective must be adjusted, repaired, or replaced as necessary.

IV.D.4. Recordkeeping and Reporting

- IV.D.4.a. The owner or operator of a gasoline transport truck subject to this Section IV.D. shall maintain records of all certification testing and repairs. The records shall identify the gasoline transport truck, the date of the test or repairs and, if applicable, the type of repair and the date of retest. The written record shall include entries of any pre-test repairs, adjustments, or modifications. These shall also include the part name, number, and vendor name of any part removed and of any part installed. The records shall be maintained in legible, readily available form for at least two (2) years after the date the testing or repair was completed and shall be made available to the Division for inspection upon request.
- IV.D.4.b. The records of certification tests required by Section IV.D.2.a. must, as a minimum, contain all of the following entries:
- IV.D.4.b.(i) The gasoline transport truck owner's name and address;
- IV.D.4.b.(ii) The gasoline transport truck/tank identification number;
- IV.D.4.b.(iii) The nature of repair work and when performed in relation to vapor tightness testing.
- IV.D.4.b.(iv) The following data for each test:
- IV.D.4.b.(iv)(A) Test pressure.
- IV.D.4.b.(iv)(B) Pressure or vacuum change, mm of water.
- IV.D.4.b.(iv)(C) Time period of test.
- IV.D.4.b.(iv)(D) Number of leaks found with instrument.

IV.D.4.b.(iv)(E) Leak definition.

IV.D.4.b.(v) The size of each of the compartments within the tank and whether such compartment was manifolded or was tested separately during pressure and vacuum tests.

IV.D.4.b.(vi) At the top of each report page shall be the company name and the date and location of the test results recorded on that page; and

IV.D.4.b.(vii) Name and title of the person conducting the test.

IV.D.4.b.(viii) For the vapor valve test required in Section IV.D.2.a.(ii)(A), the initial test pressure and time of reading.

IV.D.4.c. The records of the visual inspections required by Section IV.D.3.b.

IV.D.4.d. The owner or operator of a gasoline transport truck subject to this regulation must annually certify to the Division that the gasoline transport truck has been tested by the applicable method(s) referenced in Section IV.D.3. The certification must include:

IV.D.4.d.(i) The name and address of the company and the name and telephone number of responsible company representative over whose signature the certification is submitted; and,

IV.D.4.d.(ii) A copy of the information recorded to comply with Section IV.D.4.b.

IV.D.4.e. The records of certification tests must be kept with the tank or at the transport company office at all times and must be shown to Division personnel upon their request. Copies of all records and reports required by the provisions of this Section IV.D. must be made available to the Division upon oral or written request.

V. Crude Oil

V.A. General Exemptions

V.A.1. Storage tanks of 151,412 liters (40,000 gallons) or less used to store crude oil is exempt from the provisions of this section.

V.A.2. Storage tanks with capacities of less than 1,590 cubic meters (10,000 barrels) used to store crude oil and condensate prior to lease custody transfer are exempt from the provisions of this Regulation Number 7 other than Part D, Sections I. and II.

V.B. Equipment

Pumps and compressors handling crude oil shall be subject to the provisions of Section IV.A.

V.C. Storage

Except as provided in Section V.A.2., crude oil stored in tanks greater than 151,412 liters (40,000 gallons) shall be subject to the provisions of Sections IV.B.1.b. and IV.B.2.

VI. Petroleum Processing and Refining

VI.A. Wastewater (Oil/Water) Separators

VI.A.1. Definitions

- VI.A.1.a. "Forebays" mean the primary sections of a wastewater separator.
- VI.A.1.b. "Wastewater (oil/water) separator" means any device or piece of equipment which utilizes the difference in density between oil and water to remove oil and associated chemicals from water, or any device, such as a flocculation tank, clarifier, etc., which removes petroleum derived compounds from wastewater.

VI.A.2. The owner or operator of any wastewater (oil/water) separators at a petroleum refinery shall:

- VI.A.2.a. Equip the forebays and separator sections of the wastewater separators with one or more of the following emission control devices, ensuring that such device is properly installed, in good working order and properly maintained:
 - VI.A.2.a.(i) A solid cover with all openings sealed and the liquid contents totally enclosed.
 - VI.A.2.a.(ii) A pontoon-type or double-deck type floating roof, or internal floating cover. The floating roof or cover must rest on the surface of the liquid contents and be equipped with a closure seal or seals to close the space between the edge of the floating roof (or cover) and the wall(s) of the compartment.
 - VI.A.2.a.(iii) A vapor recovery system consisting of a vapor gathering device capable of collecting the volatile organic compound vapors discharged and a vapor disposal device capable of processing such volatile organic vapors so as to prevent their emission into the atmosphere.
 - VI.A.2.a.(iii)(A) Control devices shall meet the applicable requirements, including recordkeeping, of Part C, Sections I.A.3.a., b., c., and e., and I.A.8.a. and b.
 - VI.A.2.a.(iii)(B) The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 (September 14, 1989) shall be used to determine the efficiency of control devices.
- VI.A.2.b. Equip all openings in covers, separators, and forebays with lids or seals such that the lids or seals are in the closed position at all times except when in actual use. Access for gauging and sampling shall be minimized.

VI.B. Emissions from Petroleum Refineries

VI.B.1. Definitions

- VI.B.1.a. "Firebox" means the chamber or compartment of a boiler or furnace in which materials are burned but does not mean the combustion chamber of an incinerator.
- VI.B.1.b. "Turnaround" means the procedure of shutting a refinery unit down after a run to do necessary maintenance and repair work and then putting the unit back on stream.

VI.B.2. Process unit turnarounds

The owner or operator of a petroleum refinery shall develop and submit to the Division for approval a detailed procedure for minimization of volatile organic compound emissions during process unit turnaround. As a minimum, the procedure shall provide for:

- VI.B.2.a. Depressurization venting of the process unit or vessel to a vapor recovery system, or to a flare or firebox which assures at least 90% combustion efficiency;
- VI.B.2.b. No emission of volatile organic compounds from a process unit or vessel until its internal pressure is 17.2 psia or less; and
- VI.B.2.c. Recordkeeping of the following items. Records shall be kept for at least two years and shall be made available to the Division for review upon request.
 - VI.B.2.c.(i) Every date that each process unit is shut down,
 - VI.B.2.c.(ii) The approximate vessel volatile organic compound concentration when the volatile organic compounds were first discharged to the atmosphere, and
 - VI.B.2.c.(iii) The approximate total quantity of volatile organic compounds emitted to the atmosphere.

VI.B.3. Venting of blowdown systems and safety pressure relief valves

All blowdown systems, process equipment vents, and pressure relief valves shall be vented to a vapor recovery system, or to a flare or firebox which assures at least 90% combustion efficiency.

VI.B.4. Vacuum-Producing Systems

- VI.B.4.a. The owner or operator of any vacuum-producing system at a petroleum refinery shall not permit the emission of any noncondensable volatile organic compounds from the condensers, hot wells or accumulators of the system. This emission limit shall be achieved by:
 - VI.B.4.a.(i) Venting the noncondensable vapors to a flare or other combustion device, or,
 - VI.B.4.a.(ii) Compressing the vapors and adding them to the refinery fuel gas.

VI.B.5. All sampling, testing, and measuring ports, hatches, and access openings shall be kept in a closed sealed position except during actual sampling or access.

VI.B.6. Control devices shall meet the applicable requirements, including recordkeeping, of Part C, Sections I.A.3.a., b., c., and e., and I.A.8.a. and b.

VI.B.7. The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 (September 14, 1989), shall be used to determine the efficiency of control devices.

VI.C. Petroleum Refinery Equipment Leaks

VI.C.1. Definitions

For the purpose of this section, the following definitions apply:

- VI.C.1.a. "Accessible Component" means a component which can be reached, if necessary, by safe and proper use of portable ladders such as are acceptable to OSHA, as well as by built-in ladders and walkways. "Accessible" also includes components which can be reached by the safe use of an extension on the monitoring probe.
- VI.C.1.b. "Component" means any piece of equipment, which has the potential to leak volatile organic compounds when tested in the manner described in Section VI.C.3. These sources include, but are not limited to, pumping seals, compressor seals, seal oil degassing vents, pipeline valves, flanges and other connections, pressure relief devices, process drains, and open ended pipes. Excluded from these sources are valves which are not externally regulated.
- VI.C.1.c. "Gaseous Service" means equipment which processes, transfers or contains a volatile organic compound or mixture of volatile organic compounds in the gaseous phase.
- VI.C.1.d. "In Heavy VOC Liquid Service" means that the piece of equipment is not in gaseous service or in light VOC liquid service.
- VI.C.1.e. "In Light Liquid VOC Service" Equipment is in light liquid service if the following conditions apply:
 - VI.C.1.e.(i) the true vapor pressure of one or more of the components is greater than 0.3 kPa at 20°C. True vapor pressures may be obtained from standard reference texts or may be determined by ASTM D-2879.
 - VI.C.1.e.(ii) the total concentration of the pure components have a true vapor pressure greater than 0.3 kPa at 20°C, is equal to or greater than 20 percent by weight; and
 - VI.C.1.e.(iii) the fluid is a liquid at operating conditions.
- VI.C.1.f. "Refinery Unit" means a set of components which are a part of a basic process operation, such as, distillation, hydrotreating, cracking, or reforming of hydrocarbons.
- VI.C.1.g. "Water Draw" means a routinely used valve or system employing a valve which allows non-VOC material (usually water) to be separated from VOC.

VI.C.2. Provisions for Specific Processes

- VI.C.2.a. The owner or operator of a petroleum refinery complex subject to this regulation shall:
- VI.C.2.a.(i) Develop a monitoring program consistent with the provisions in Section VI.C.3.
 - VI.C.2.a.(ii) Conduct a monitoring program consistent with the provisions in Section VI.C.4.a.
 - VI.C.2.a.(iii) Record all leaking components which have a VOC concentration exceeding 10,000 ppm when tested according to Section VI.C.3., and place an identifying tag on each component consistent with the provisions in Section VI.C.4.a.(iii).
 - VI.C.2.a.(iv) Repair and retest leaking components, as defined in Section VI.C.2.a.(iii), as soon as possible, but no later than fifteen (15) days after the leak is found, excepting those specified in Sections VI.C.2.a.(v) and VI.C.2.a.(vi).
 - VI.C.2.a.(v) Identify all leaking components as defined in Section VI.C.2.a.(iii), which cannot be repaired until the unit is shut down for turnaround, and repair and retest as in Section VI.C.2.a.(iv) when the unit is back on stream.
 - VI.C.2.a.(vi) When a component leak cannot be fixed within fifteen (15) working days solely because parts are not available, the following shall be noted in an "awaiting parts log:"
 - VI.C.2.a.(vi)(A) component identification and tag number
 - VI.C.2.a.(vi)(B) date part was ordered
 - VI.C.2.a.(vi)(C) date part was received
 - VI.C.2.a.(vi)(D) date repair was made
- VI.C.2.b. Except for safety pressure relief valves, no owner or operator of a petroleum refinery shall install or operate a valve at the end of a pipe or line containing volatile organic compounds unless the pipe or line is sealed with a second valve, a blind flange, a plug, or a cap. The sealing device may be removed only when a sample is being taken or when the valve is otherwise in use.
- VI.C.2.c. The Division, at its discretion, may require early unit turnaround based on the number and severity of tagged leaks awaiting turnaround provided:
- VI.C.2.c.(i) The requirement does not exceed reasonable available control technology due to cost per ton of emissions reduction achieved by the early turnaround or other reasonable analysis.
 - VI.C.2.c.(ii) The Division provides the owner or operator of a petroleum refinery with written notification at least 180 days before requiring

an early turnaround. The owner or operator will have 30 days from the date of the Division's notification to contest the requirement by submitting a demonstration that the requirement is beyond reasonable available control technology. If no demonstration is made, it will be assumed the requirement is reasonable. If a demonstration is submitted by the owner or operator, the Division will either approve the demonstration or disapprove the demonstration with a justification regarding the disapproval within 30 days of the date the demonstration is submitted to the Division.

VI.C.2.c.(iii) The requirement is not contested by the owner or operator. Should the requirement be contested, the requirement for early unit turnaround will be delayed until 180 days after the demonstration discussed in Section VI.C.2.c.(ii) is disapproved by the Division.

VI.C.2.d. Piping valves and pressure relief valves in gaseous VOC service shall be marked in some manner that will be readily obvious to both refinery personnel performing monitoring and the Division, to identify them as components which are monitored quarterly.

VI.C.3. Testing and Monitoring Procedures

Testing and calibration procedures to determine compliance with this regulation shall be consistent with EPA reference method 21 of 40 CFR Part 60 (September 14, 1989). The reference compound may be methane or hexane. A leak is defined as a reading of 10,000 ppmv of the reference compound.

VI.C.4. Monitoring, Recordkeeping, Reporting

VI.C.4.a. Monitoring

VI.C.4.a.(i) The owner or operator of a petroleum refinery subject to this regulation shall conduct a monitoring program consistent with the following provisions:

VI.C.4.a.(i)(A) Monitor yearly by the method referenced in Section VI.C.3., all:

- | | |
|--------------------|--|
| VI.C.4.a.(i)(A)(1) | Pump seals; and |
| VI.C.4.a.(i)(A)(2) | Piping valves in light liquid VOC service; and |
| VI.C.4.a.(i)(A)(3) | Process drains; and |
| VI.C.4.a.(i)(A)(4) | Heat-exchanger body flanges; and |
| VI.C.4.a.(i)(A)(5) | Other accessible flanges in VOC service. |
| VI.C.4.a.(i)(A)(6) | Components in heavy liquid VOC service are exempt from requirements of this Section VI.C.4.a.(i)(A). |

VI.C.4.a.(i)(B) Monitor quarterly by the method referenced in Section VI.C.3., all:

VI.C.4.a.(i)(B)(1) Compressor seals; and

VI.C.4.a.(i)(B)(2) Piping valves in gaseous service; and

VI.C.4.a.(i)(B)(3) Pressure relief valves in gaseous service.

VI.C.4.a.(i)(C) Monitor at least weekly by visual methods all pump seals.

VI.C.4.a.(i)(D) Monitor within 24 hours with a VOC detector and make record of any component from which VOC liquids are observed leaking.

VI.C.4.a.(i)(E) Components in heavy liquid VOC service shall be monitored by the method referenced in Section VI.C.3. within five days if evidence of a potential leak is found by visual, audible, olfactory, or any other detectable method.

VI.C.4.a.(ii) Inaccessible valves and flanges shall be monitored annually or, as a minimum, at unit shutdown using the procedures of VI.C.2.a.(v). Pressure relief devices which are connected to an operating flare header or vapor recovery device, storage tank valves, and valves that are not externally regulated are exempt from the monitoring requirements in Section VI.C.4.a.(i).

VI.C.4.a.(iii) The owner or operator of a petroleum refinery, upon the detection of a leaking component as defined in Section VI.C.2.a.(iii), shall affix a weatherproof and readily visible tag, bearing an identification number and the date the leak is located, to the leaking component. This tag shall remain in place until the leaking component is repaired. In addition, the owner or operator shall log the leak (including those leaks immediately repaired), per the requirements of Sections VI.C.4.b.(i) through (iii).

VI.C.4.b. Recordkeeping

VI.C.4.b.(i) The owner or operator of a petroleum refinery shall maintain a leaking components monitoring log which shall contain at a minimum, the following data:

VI.C.4.b.(i)(A) The name of the process unit where the component is located.

VI.C.4.b.(i)(B) The type of component (e.g., valve, seal).

VI.C.4.b.(i)(C) The tag number of the component.

VI.C.4.b.(i)(D) The date on which a leaking component is discovered.

VI.C.4.b.(i)(E) The date on which a leaking component is repaired.

- VI.C.4.b.(i)(F) The date and instrument reading found during the recheck procedure subsequent to repairing a leaking component.
- VI.C.4.b.(i)(G) A record of the calibration of the monitoring instrument.
- VI.C.4.b.(i)(H) Those leaks that cannot be repaired until turnaround.
- VI.C.4.b.(i)(I) The total number of components checked and the total number of components found leaking.
- VI.C.4.b.(i)(J) The total number of components subject to Section VI.C.2.a.(v) which upon retest were still leaking as defined in Section VI.C.3.
- VI.C.4.b.(ii) Copies of the monitoring log shall be retained by the owner or operator for a minimum of two (2) years after the date on which the record was made or report prepared.
- VI.C.4.b.(iii) Copies of the monitoring log shall be made available to the Division upon oral or written request.

VI.C.4.c. Reporting

The owner or operator of a petroleum refinery, upon the completion of each yearly and/or quarterly monitoring procedure, shall:

- VI.C.4.c.(i) Submit a report to the Division by the 15th day of February, May, August, and November that lists all leaking components that were located during the previous three (3) calendar months (quarter), but not repaired within fifteen (15) working days, all leaking components awaiting unit turnaround, the total number of components inspected, and the total number of components found leaking.
- VI.C.4.c.(ii) Submit a signed statement with the report attesting to the fact that, with the exception to those leaking components listed in Section VI.C.4.b.(i)(H), all monitoring and repairs were performed as stipulated in the monitoring program.

VII. Control of Volatile Organic Compound Leaks from Vapor Collection Systems and Vapor Control Systems Located at Gasoline Terminals, Gasoline Bulk Plants, and Gasoline Dispensing Facilities

VII.A. General Provisions

VII.A.1. Applicability

This section is applicable to all gasoline terminals, gasoline bulk plants, and gasoline dispensing facilities (e.g., service stations) which are located in ozone nonattainment areas and which must have a vapor collection system pursuant to Section IV. and other applicable rules.

VII.A.2. Exemptions

This section is not applicable to those operations involving transfer of gasoline from gasoline dispensing facilities to motor vehicle fuel tanks nor to other dispensing operations at such facilities.

VII.A.3. Definitions

For the purpose of this section, the following definitions apply:

- VII.A.3.a. "Gasoline Dispensing Facility" means any site where gasoline is dispensed to motor vehicle fuel tanks from stationary storage tanks, (e.g., service stations, fleet pumps, etc.)
- VII.A.3.b. "Gasoline Transport Truck" means tank trucks or trailers equipped with a storage tank and used for the transport of gasoline from sources of supply to stationary storage tanks of gasoline dispensing facilities (e.g., service stations), bulk gasoline plants or gasoline terminals.
- VII.A.3.c. "Vapor Collection System" means a vapor transport system which uses direct displacement by the gasoline being transferred to force vapors from the vessel being loaded into either a vessel being unloaded or a vapor holding tank.

VII.B. Specific Provisions

VII.B.1. The operator of a vapor collection system at a facility subject to the provisions of this section shall operate the vapor collection system and the gasoline loading equipment in a manner that prevents:

- VII.B.1.a. Gauge pressure from exceeding 33.6 torr (18 inches of H₂O) and vacuum from exceeding gauge pressure of minus 11.2 torr (minus 6 inches of H₂O) at the point where the vapor return line on the truck connects with the vapor collection line of the facility.
- VII.B.1.b. A reading equal to or greater than 100 percent of the lower explosive limit (LEL, measured as propane) at 2.5 centimeters from a known or potential leak source when measured by the procedures described in Appendix B of "Control of Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems," December 1978, EPA-450/2-78-051, during loading or unloading operations at gasoline dispensing facilities, bulk plants, and terminals.
- VII.B.1.c. Avoidable liquid or vapor leaks from the system during loading or unloading operations at gasoline dispensing facilities, bulk plants, and terminals.
- VII.B.1.d. Division representatives may monitor for excessive back pressure as defined by Section VII.B.1.a. and vapor leakage as is defined by Section VII.B.1.b. or by detection methods incorporating sight, sound, and smell.

VII.B.2. Repairs and Modifications

- VII.B.2.a. The operator shall within fifteen (15) days, repair and retest a vapor collection system that exceeds the pressure limits (Section VII.B.1.a.), excepting that;

- VII.B.2.b. Should an applicable facility require modification or repairs that will take longer than fifteen (15) days to complete, the operator shall submit to the Division for approval a schedule which includes dates of commencement and completion.

Appendix B Criteria for Control of Vapors from Gasoline Transfer to Storage Tanks

- I. Drop Tube Specifications. Submerged fill is specifically required. The drop tube must extend to within 15.24 cm (6 in.) of the tank bottom.
- II. Vapor Hose Return. Vapor return line and any manifold must be minimum 7.6 cm (3 in.) ID. All tanks must be provided with individual overfill protection. (Liquid must not be allowed in the vent line or vapor recovery line.) Disconnect on liquid line should assure that all liquid in the hose is drained into the storage tank. The requirements for overfill protection as specified may be waived for existing storage tanks when it is demonstrated to the satisfaction of the appropriate local Fire Marshal, and where applicable, the State Oil Inspection Office that the installation of overfill protection devices on existing tanks is physically not possible.
- III. Size of Vapor Line Connections. For separate vapor lines, nominal three inch (7.6 cm) or larger connections must be utilized at the storage tank and truck. However, short lengths of 2-inch (5.1 cm) vertical pipe no greater than 91.4 cm (3 ft.) long are permissible if the fuel delivery rate is less than 400 gallons per minute.

Where concentric (coaxial) connections are utilized, a 45 cm² (7 sq. in.) area for vapor return shall be provided. Four-inch concentric designs are acceptable only when using a venturi-shaped outer tube or where normal drop rate of 1,700 liters per minute (450 gpm) is reduced by at least 25%. Six-inch (15.24 cm) risers should be installed in new stations with concentric connections.

- IV. Type of Liquid Fill Connection. Vapor tight caps are required for the liquid fill connection for all systems. A positive closure utilizing a gasket is necessary to prevent vapors from being emitted at ground level. Cam-lock closures meet this requirement. Dry break closures are preferred.
- V. Tank Truck Inspection. Tank trucks are specifically required to be vapor-tight and to have valid leak-tight certification. The visual inspection procedure must be conducted at least once every six months to ensure properly operating manifolding and relief valves, using the test procedure of Section IV.D.3.b.
- VI. Dry Break on Underground Tank Vapor Riser. Dry-break closures are required to assure transfer of displaced vapors to the truck and to prevent ground-level, gasoline-vapor emissions caused by failure to connect the vapor return line to the underground tanks (closure on riser to mate with opening on hose). These devices keep the tank sealed until the hose is connected to the underground tank. Concentric couplers without dry-breaks are required to have a dry-break on the vapor line connection to the coupler itself, rather than on the rise pipe from the storage tank. The liquid fill riser should be provided with a gap having a positive closure (threaded or latched).
- VII. Equipment Ensuring Vapor-Hose Connection during Gasoline Deliveries. An equipment system aboard the tank truck shall insure (barring deliberate tampering) that a vapor return hose is connected from the truck's vapor return line to the tank receiving gasoline.
- VIII. Vent Line Restriction Devices. Vent line restriction devices are required. If the liquid fill line were attached to the underground tank and the vapor return line were disconnected, then dry break closures would seal the vapor return path to the truck, forcing all vapors out the vent line. In such instances, a restriction device on this vent line greatly reduces fill rate, warning the operator that the vapor line is not connected.

Pressure/vacuum (PV) vent valves installed on the storage tank vent pipes. The pressure specifications for PV vent valves shall be: a positive pressure setting of 2.5 to 6.0 inches of water and a negative pressure setting of 6.0 to 10.0 inches of water.

- IX. Fire and Safety Regulations. All new or modified installations must comply in their entirety with all code requirements including NFPA, Pamphlet 30 (fiberglass is preferred for new manifold lines). For any questions concerning compliance, please contact State Oil Inspection or your local Fire Marshal.
- X. State Oil Inspection. Requirements of the State Oil Inspection office make accurate measurements of the liquid in the underground tank necessary. Vapor-tight gauging devices will be required in all systems designed such that a pressure other than atmospheric will be held or maintained in the storage tank. The volume of liquid in the tanks maintained at atmospheric pressure may be determined with a stick through the submerged drop tube or through a separate submerged gauging tube extending to within 15.24 cm (6 in.) of the tank bottom.

Appendix C Criteria for Control of Vapors from Gasoline Transfer at Bulk Plants

I. Storage Tank Requirements:

- A. Drop Tube Specification: Underground tanks must contain a drop tube that extends to within six inches (15.24 cm) of the tank bottom. All top loaded above-ground tanks must contain a similar drop tube. Above-ground tanks using bottom loading, where the inlet is flush with the tank bottom, must meet the submerged fill requirement.
- B. Size of Vapor Lines from Storage Tanks to Loading Rack: See nomograph (Attachment 1). NOTE: Affected sources are free to choose a pipe diameter different from the one suggested by the nomograph if sufficient justification and documentation is presented.
- C. Pressure Relief Valves: All pressure relief valves and valve connections must be checked periodically for leaks, and be repaired as required. The relief valve pressures should be set in accordance with Sections 2-2.5.1 and 2-2.7.1 inclusive of the current National Fire Protection Agency Pamphlet Number 30.
- D. Liquid Level Check Port: Access for checking liquid level by other than a vapor-tight gauging system shall be vapor-tight when not being used. Tank level shall be checked prior to filling to avoid overfills.
- E. Miscellaneous Tank Openings: All other tank openings, e.g., tank inspection hatches, must be vapor tight when not being used, and must be closed at all times during transfer of fuel.

- F. Storage Tank Overfill Protection: Except for concentric (coaxial) delivery systems, underground tanks must have ball check valves (stainless steel ball). Tanks with concentric delivery systems must have Division-approved overfill protection, (e.g., cutoff pressure-switch in vent line).

II. Loading Rack Requirements:

- A. Loading Specification: A vapor-tight bottom-loading or top-loading system using submerged fill with a positive seal, e.g., the Wiggins (tm) system, is required. NOTE: Bulk plants delivering solely to exempt accounts are required to have submerged fill, but loading need not be vapor-tight.
- B. Dry-Break on Storage Tank Vapor Return Line: A dry-break is required to prevent ground-level gasoline vapor emissions during periods when gasoline transfer is not being made. This device keeps the tank sealed until the vapor return hose is connected.

III. Tank Truck* Requirements:

- A. Vapor Return Modification: Tank trucks must be modified to recover vapors during loading and unloading operations. NOTE: Tank trucks making deliveries solely to exempt accounts do not require this modification. However, 97% submerged fill is required when top loading.
- B. Loading Specifications: Bottom loading or top loading using submerged fill with a positive seal is required for tank trucks modified for vapor recovery. NOTE: When loading a tank truck with this modification without the vapor return hose connected (this is allowed at bulk plants servicing exempt accounts returning without collected vapors in the tank), the requirements of National Fire Protection Agency Pamphlet Number 385, "Loading and Unloading Venting Protection in Tank Vehicles, Section 2219, Paragraph c", must be met.
- C. Vapor Return Hose Size: A minimum three-inch (7.6 cm) ID vapor return hose is required.
- D. Tank Truck Inspection: Tank trucks are required to be vapor-tight and have valid leak-tight certification. Periodic visual inspection is necessary to insure properly operating manifolding and relief valves.

* The term "tank truck" is meant to include all trucks with tanks used for the transport of gasoline, such as tank wagons, account trucks and transport trucks.

PART C Surface Coating, Solvents, Asphalt, Graphic Arts and Printing, and Pharmaceuticals

I. Surface Coating Operations

I.A. General Provisions

I.A.1. Definitions, unless otherwise specified in Sections I.B. through I.O.

I.A.1.a. "Coating" means a protective, functional or decorative film applied in a thin layer to a surface. This term often applies to paints such as lacquers or enamels, but is also used to refer to films applied to paper, plastics, or foils.

I.A.1.b. "Coating Applicator" means an apparatus used to apply a surface coating.

- I.A.1.c. "Coating Line" means an operation which includes both (1) a coating applicator and (2) device(s) and/or area(s) to accomplish one or more of the following processes: flash-off, drying, curing, heat-setting and/or polymerization.
- I.A.1.d. "Coating Solids" means that portion of a surface coating, which remains after volatile components have escaped.
- I.A.1.e. "Final Repair Application" means that application of surface coating specifically intended to repair damage and imperfections in existing surface coats.
- I.A.1.f. "Finished Coating Solids" means those coating-solids that remain on a coated substance after completion of all production processes.
- I.A.1.g. "Flash-off Area" means the space between the application area and the oven.
- I.A.1.h. "Prime Coat" (also termed "primer") means the first film of coating applied in a multiple-coat operation.
- I.A.1.i. "Single Coat" means a single film of coating applied directly to the metal substrate, omitting the primer application.
- I.A.1.j. "Surface Coating" means a liquid, liquefiable, or mastic composition which is converted to a solid (or semi-solid) protective, decorative, or adherent film or deposit after application as a thin layer or by impregnation. In a machine which has both coating and printing units, all units shall be considered as performing a printing operation. Such a machine is subject to the standards governing graphic arts, and thus is not covered by coating standards.
- I.A.1.k. "Surface Coating Oven" means a chamber within which heat is used to bake, cure, polymerize, and/or dry a surface coating.
- I.A.1.l. "Topcoat" means the final film of coating applied in a multiple-coat operation.

I.A.2. Abbreviations

- I.A.2.a. Kg/lc shall be the abbreviation for: kilograms of solvent VOC per liter of coating (minus water and "exempt" solvents, as defined in Part A, Section II.B.).
- I.A.2.b. Lb/gc shall be the abbreviation for: (avoirdupois) pounds of solvent VOC per gallon of coating (minus water and "exempt" solvents, as defined in Part A, Section II.B.).

I.A.3. Test Methods and Procedures

- I.A.3.a. The owner or operator of any VOC source required to comply with this section shall, at their own expense, demonstrate compliance using EPA reference method 24 of 40 CFR Part 60 (September 14, 1989) for surface coatings, and reference method 25 and reference methods 1 through 4 (September 14, 1989) for add-on controls.

- I.A.3.b. The test protocol should be in accordance with the requirements of the Air Pollution Control Division Compliance Test Manual and shall be submitted to the Division for review and approval at least thirty (30) days prior to testing. No test shall be conducted without prior approval from the Division.
- I.A.3.c. The Division may use independent tests to verify test data submitted by the source operator or owner. The test methods shall be those listed in Section I.A.3.a. and the Division test results shall take precedence.
- I.A.3.d. The Division may accept, instead of the testing required in this section, a certification by the manufacturer of the composition of the coatings if supported by actual batch formulation records. The owner or operator of the VOC source required to comply with this section shall obtain certification from the coating manufacturer(s) that the test method(s) used for determination of VOC content meet the requirements specified in Section I.A.3.a. The owner or operator shall have this certification readily available to Division personnel, in order to allow the results to be used in the daily compliance calculations specified in Section I.A.10.
- I.A.3.e. The performance of add-on control device equipment shall be established with the required test methods of I.A.3.a. at equipment startup, and after major modification to the control equipment. Baseline operating parameters shall be established during the satisfactory (i.e. in-compliance) operation of the control equipment, including operation during all anticipated ranges of process throughput. During subsequent process operation, the owner or operator shall maintain the operating conditions of the add-on controls as close to these baseline conditions as possible. If serious operational problems with an add-on control system are evidenced from the daily monitoring required by Section I.A.8.b. (such problems may be indicated by changes from baseline conditions), repeat performance tests may be required by the Division, as necessary.

I.A.4. Sampling

To determine compliance with applicable surface coating standards, samples shall be taken from the coating as freshly delivered to the reservoir of the coating applicator.

I.A.5. Alternative compliance methods for processes and operations

For each process specified in Sections I.B. through I.N. the emission limits designated for that process shall be achieved by:

- I.A.5.a. Use of coatings with proportions of VOC less than or equal to the maximums specified by the applicable section of this regulation; or
- I.A.5.b. Use of the specified equipment and procedures prescribed by the applicable section of this regulation; or
- I.A.5.c. Use of an alternative means of control which satisfies the requirements of Section I.A.5.e., I.A.5.f., and Part A, Section II.D.; or
- I.A.5.d. Use of crossline averaging. The emission trading requirements of Regulation Number 3, Part A, Section V. shall be met. In addition, the following requirements apply:

- I.A.5.d.(i) The actual reduction shall be equivalent to the actual reduction that would be achieved on a line-by-line basis.
- I.A.5.d.(ii) Credit shall not be received for downtime, however, credit is allowed for enforceable production limits.
- I.A.5.d.(iii) Crossline averaging shall be used only across lines in the same control technique guidance group.
- I.A.5.d.(iv) The emission trading policy shall be met on a daily weighted average.
- I.A.5.d.(v) Sources subject to best available control technology (BACT) and lowest achievable emission rate (LAER) requirements shall not use cross line averaging.
- I.A.5.d.(vi) VOC emissions shall be expressed as lbs/gallons solids to determine reduction over baseline (lb VOC/lb solids for graphic arts).
- I.A.5.d.(vii) Organisol and plastisol coatings shall not be used to bubble emissions from vinyl surface or automobile topcoating operations.
- I.A.5.d.(viii) Before crossline averaging may be used, the control methodology shall be approved as a revision to the State Implementation Plan.

I.A.5.e. The design, operation and efficiency of any capture system used in conjunction with any emission control system shall be certified in writing by the source owner or operator and approved by the Division. Unless the capture system meets the requirements for a total enclosure as specified in the New Source Performance Standard for the Magnetic Tape Manufacturing Industry, 53FR38892, October 3, 1988, or unless Division approved material balance techniques are used to adequately determine overall VOC capture and destruction/recovery efficiency, the efficiency of the capture system shall be determined by test methods approved as a revision to the State Implementation Plan. Testing for capture efficiency shall be performed on a case-by-case basis as required by the Division. The requirements of Sections I.A.3.e. and I.A.8.b. shall apply to the capture and control device system. When capture and control device efficiency must be independently determined, the overall VOC emission reduction rate equals the (percent capture efficiency X percent control device efficiency)/100.

I.A.5.f. Sources which use add-on controls, crossline averaging, or an approved alternative control strategy instead of low solvent technology to meet the applicable emission limit shall meet the equivalent VOC emission limit, on the basis of solids applied (lb VOC/gal solids applied, or lb VOC/lb solids applied, for graphic arts sources). Appendix E sets forth the procedure for converting emission limits and lists equivalent limits for various coating operations.

I.A.5.g. Owners or operators of sources which use a carbon adsorption system shall provide for the proper disposal or reuse of all VOC recovered.

I.A.6. Exemptions

I.A.6.a. The requirements of this Section I. do not apply to sources used exclusively for chemical or physical analysis or determination of product quality and commercial acceptance, provided;

I.A.6.a.(i) the operation of the source is not an integral part of the production process; and

I.A.6.a.(ii) the emissions from the source do not exceed 363 kilograms (800 lbs.) in any calendar month; and

I.A.6.a.(iii) the exemption is approved in writing by the Division.

I.A.6.b. The requirements of Sections I.C., D., E., F., G., H., I., L. and M. are not applicable to sources whose actual emissions, including fugitive emissions, before add-on controls, are less than 6.8 kilograms (15 lbs.) per day and less than 1.4 kilograms (3 lbs.) per hour. Emissions from all sources within the same control technique guidance group shall be totaled to determine actual emissions.

I.A.7. Fugitive emission control

I.A.7.a. Control techniques and work practices shall be implemented at all times to reduce VOC emissions from fugitive sources. Control techniques and work practices include, but are not limited to:

I.A.7.a.(i) tight-fitting covers for open tanks;

I.A.7.a.(ii) covered containers for solvent wiping cloths;

I.A.7.a.(iii) proper disposal of dirty cleanup solvent.

I.A.7.b. Emissions of organic material released during clean-up operations, disposal, and other fugitive emissions shall be included when determining total emissions, unless the source owner or operator documents that the VOCs are collected and disposed of in a manner that prevents evaporation to the atmosphere.

I.A.8. Recordkeeping, Reporting, and Monitoring

I.A.8.a. If add-on control equipment is used, continuous monitors of the following parameters shall be installed, calibrated, and operated at all times that the associated control equipment is operating:

I.A.8.a.(i) exhaust gas temperature of all incinerators;

I.A.8.a.(ii) temperature rise across a catalytic incineration bed;

I.A.8.a.(iii) breakthrough of VOC on a carbon adsorption unit;

I.A.8.a.(iv) any other monitoring and/or recording device, maintenance and/or control-media-replacement schedule(s) specified on a case-by-case basis by the Division.

I.A.8.b. If add-on control equipment is used, in addition to the requirements of Section I.A.8.a., the following information and any other necessary information, as determined applicable for each source by the Division, shall be monitored and recorded daily in order to assure continuous compliance. The substitution of continuous recordings for daily recording may be allowed by the Division.

I.A.8.b.(i) For the capture system: fan power use, duct flow, duct pressure.

I.A.8.b.(ii) For carbon adsorbers: bed temperature, bed vacuum pressure, pressure at the vacuum pump, accumulated time of operation, concentration of VOC in the outlet gas, solvent recovery.

I.A.8.b.(iii) For refrigeration systems: compressor discharge and suction pressures, condenser fluid temperature, solvent recovery.

I.A.8.b.(iv) For incinerator systems: exhaust gas temperature, temperature rise across a catalytic incinerator bed, flame temperature, accumulated time of incinerator.

I.A.8.c. Recordkeeping procedures shall follow the guidance in "Recordkeeping Guidance Document for Surface Coating Operations and the Graphic Arts Industry," July 1989, EPA 340/1-88-003.

I.A.9. Required and Prohibited Acts

I.A.9.a. No owner or operator of a source of VOCs subject to this section shall operate, cause, allow or permit the operation of the source, unless:

I.A.9.a.(i) For each category of surface coating as specified in Sections I.B. through I.M., the owner or operator of a surface coating line or facility subject to that section does not cause, allow or permit the discharge into the atmosphere of any VOCs in excess of the specified emission limit, calculated as delivered to the coating applicator or as applied to the substrate, whichever is greater.

I.A.9.a.(ii) The owner or operator of a surface coating operation maintains and operates surface coating operations in a manner consistent with good air pollution control practices for minimizing emissions, such as, but not limited to, coating application methods capable of achieving a transfer efficiency achieved by HVLP spraying.

I.A.10. Compliance Calculation Procedures

I.A.10.a. Compliance with this section shall be determined on a daily basis. Sources may request a revision to the State Implementation Plan for longer times for compliance determination.

I.A.10.b. Compliance calculation procedures shall follow the guidance in "Procedure for Certifying Quantity of Volatile Organic Compounds Emitted by Paint, Ink, and Other Coatings," December 1984, EPA-450/3-84/019. In addition, for add-on controls or other compliance alternatives, calculation procedures shall follow the guidance of Section I.A.5.f.

- I.A.11. The requirements of Sections I.A.1. through I.A.10. apply to each category of surface coating as specified in Sections I.B. through I.M. The requirements of Sections I.A.7. through I.A.10. apply to the category in Section I.N. The requirements of Sections I.A.1. through I.A.9 apply to the category in Section I.O.
- I.A.12. The Division shall approve utilization of alternative compliance methods to the following sources pursuant to this Section I.
- I.A.12.a. Lexmark International, Inc. shall be allowed to utilize the alternative compliance method of crossline averaging for processes and operations within the Manufactured Metal Parts and Metal products (Subgroup L) and within the Plastic Film Coating Operations (Subgroup J). The emission trading requirements of Regulation Number 3, Part A, Section V. shall be met, and utilization of the alternative compliance method shall be subject to the following generic conditions, which shall be written and specifically described as enforceable permit terms and conditions in its permits:
- I.A.12.a.(i) The alternative compliance method shall result in an actual reduction that is equivalent to the actual reduction that would otherwise be achieved on a line-by-line basis pursuant to this Regulation Number 7.
- I.A.12.a.(ii) Credit shall not be received for downtime; however, credit is allowed for emission reductions from enforceable production limits.
- I.A.12.a.(iii) Cross line averaging shall be used only across lines of the same control technique guidance group. Lexmark shall use cross line averaging between Metal Parts and Metal Products lines or between Plastic Film Coating lines. Lexmark shall not use cross line averaging where the emissions from Plastic film coating lines are averaged with Metal Parts and Metal Products lines.
- I.A.12.a.(iv) The emission trading policy set forth in Regulation Number 3, Part A, Section V., shall be met on a daily weighted average.
- I.A.12.a.(v) Sources subject to Best Available Control Technology (BACT), and Lowest Achievable Emission Rate (LAER) shall not use cross line averaging.
- I.A.12.a.(vi) To determine reduction over baseline, VOC emissions shall be expressed according to Section I.A.5.f., as lbs/gallons solids.
- I.A.12.a.(vii) Monthly records shall be kept at the source to verify ongoing compliance with these conditions. The recordkeeping format shall be approved by the Division.
- I.A.12.a.(viii) An annual report demonstrating ongoing compliance with this regulation and all permit terms shall be filed with the Division. The report format shall be approved by the Division and specifically described in the permit.

- I.A.12.a.(ix) The Division shall issue a permit with federally enforceable terms and conditions to Lexmark limiting Lexmark's alternative compliance method emissions to those allowable under Section I.L. and Section I.J.
- I.A.12.a.(x) Commercial and Product quality control laboratory equipment are exempt from APEN filing and construction permit requirements under Regulation Number 3, Part A, Section II.D.1.(i), and Regulation Number 3, Part B, Section II.D.1.a.; and from construction permit requirements under Regulation Number 3, Part B, Section II.D.1.(i). Qualifying sources shall be exempt from Regulation Number 7, Section I. A.6.
- I.A.12.a.(xi) Nothing in the alternative compliance method is intended to relax any emissions limitation of this Regulation Number 7.

I.B. Automobile and Light-Duty Truck Assembly Plants

I.B.1. Definitions

- I.B.1.a. "Application Area" means the area where the surface coating is applied by spraying, dipping or flow coating.
- I.B.1.b. "Automobile" means a passenger motor-vehicle or a derivative of same, capable of seating twelve (12) or fewer passengers, and having at least two driven wheels.
- I.B.1.c. "Automobile Assembly Facility" means a facility where parts (including assembled or partially assembled components) of automobiles are received, and finished automobiles are produced, partially or wholly by an assembly line.
- I.B.1.d. "Light-Duty Truck" means any motor vehicle rated at 8,500 pounds (3,855 kilograms) gross vehicle weight or less, and having at least two driven wheels, which is designed primarily for purposes of transportation of property or is a derivative of such vehicles. It includes, but is not limited to, pickup trucks, vans, and window vans rated at 8,500 pounds' gross vehicular weight or less.
- I.B.1.e. "Light-Duty Truck Assembly Facility" means a facility where parts (including assembled or partially assembled components) of light-duty trucks are received, and finished light-duty trucks are produced, partially or wholly by an assembly line.

I.B.2. Applicability

This section applies to all assembly and subassembly lines in an automobile or light-duty truck assembly facility, including those for frames, small parts, wheels, and main body parts. This section applies only to the manufacture of new vehicles.

I.B.3. Emission Limitations

	Kg/lc	Lb/gc
Prime application, flashoff area, and oven	0.23	1.9
Topcoat application area, flashoff area, and oven	0.34	2.8
Final repair application, flashoff area and oven	0.58	4.8

I.B.4. Coatings other than primer, surfacer (guidecoat), topcoat and final repair shall be considered under the miscellaneous metal parts Section I.L.

I.B.5. For topcoat application, if a complying coating is not used to meet the emission limit of Section I.B.3, then:

I.B.5.a. the alternate method shall meet an emission limit of 15.1 lb VOC/gal. solids deposited on the coated part; and

I.B.5.b. compliance shall be determined on a daily weighted average basis.

I.B.6. Topcoat operation shall include all spray booths, flash-off areas and ovens in which topcoat is applied, dried and cured, except for final offline repair.

I.C. Can Coating Operations

I.C.1. Definitions

I.C.1.a. "Can Coatings" means any coatings containing organic materials and applied -- or intended for application -- by spray, roller, or other means onto the inside and/or outside surfaces of formed cans and components of cans.

I.C.1.b. "End Sealing Compound" means a substance which is coated onto can ends and which functions as a seal when the end is assembled onto the can.

I.C.1.c. "Exterior Base Coat" means a coating applied to the exterior of a can to provide protection to the metal and/or to provide background for any lithographic or printing operation.

I.C.1.d. "Interior Base Coat" means the initial coating applied to the interior surface of a can by roller coater or spray.

I.C.1.e. "Interior Body Spray" means a coating sprayed onto the interior surface of the can body to provide a protective film between the can and its contents.

I.C.1.f. "Overvarnish" means a coating applied directly over ink to reduce the coefficient of friction, provide gloss, protect against abrasion, enhance product quality, and protect against corrosion.

I.C.1.g. "Three-Piece Can Side Seam Spray" means a coating sprayed onto the interior and/or exterior of a can body seam on a three-piece can to protect the exposed metal.

I.C.1.h. "Two-Piece Can Exterior End Coat" means a coating applied to the exterior of the bottom end of a two-piece can.

I.C.2. Applicability

This section applies to coating applicator(s), and oven(s) of sheet can or end coating lines involved in sheet basecoat (exterior and interior) and over varnish, two-and three-piece can interior body spray, two-piece can exterior end (spray or roll coat), three-piece can side-seam spray, and end sealing compound operations.

I.C.3. Emission Limitations

Can Coating	Kg/lc	Lb/gc
Sheet base coat (exterior and interior) and overvarnish two-piece can exterior (base coat and overvarnish)	0.34	2.8
Two and three-piece can interior body spray, two-piece can exterior end (spray or roll coat)	0.51	4.2
Three-piece can side-seam spray	0.66	5.5
End sealing compound	0.44	3.7
Any additional coats	0.51	4.2

I.D. Coil Coating Operations

I.D.1. Definitions

I.D.1.a. "Coil Coating" means any surface coating applied by spray, roller, or other means onto one or both surfaces of flat metal sheets or strips that come in rolls or coils.

I.D.1.b. "Quench Area" means a chamber where the hot metal exiting the oven is cooled by either a spray of water or a blast of air followed by water cooling.

I.D.2. Applicability

This section applies to the coating applicator(s), oven(s), and quench area(s) of coil coating operations involved in primer, intermediate, top-coat or single-coat operations.

I.D.3. Emission Limitations:

Coil Coating	Kg/lc	Lb/gc
Any coat (primer, intermediate coat, topcoat, single coat)	0.31	2.6

I.E. Fabric Coating Operations

I.E.1. Definitions

I.E.1.a. "Fabric Coating" means the process of coating or impregnating the full, usable surface of a fabric web or sheet to impart properties that are not initially present such as strength, stability, water or acid repellency, or appearance. "Fabric Coating" excludes those processes normally included under fabric finishing (e.g. dyeing, treating for stain and wrinkle resistance, etc.).

I.E.2. Applicability

This section applies to fabric coating lines which includes, but is not limited to, coaters and drying ovens.

I.E.3. Emission Limitations

	Kg/lc	Lb/gc
Fabric Coating Line	0.35	2.9

I.F. Large Appliance Coating Operations

I.F.1. Definition

I.F.1.a. "Large Appliances" includes doors, cases, lids, panels, interior support parts, and any other large (greater than one square decimeter (15.5 square inches)) coated surfaces of residential and commercial washers, dryers, ovens, ranges, refrigerators, freezers, water heaters, dishwashers, trash compactors, air conditioners, and all other products under SIC Code 363 according to the "Standard Industrial Classification Manual", Executive Office of the President, Office of Management and Budget, designated by convention of the industry as large appliances.

I.F.2. Applicability

This section applies to all large appliance coating lines.

I.F.3. Emission Limitations

	Kg/lc	Lb/gc
Large Appliance Coating Line; prime, single or topcoat application area, flashoff area, and oven	0.34	2.8

I.G. Magnet Wire Coating Operations

I.G.1. Definition

I.G.1.a. "Magnet Wire Coating" means those operations which apply a coating of electrically insulating varnish or enamel (or similar substance) to wire which is known as "magnet wire." Magnet wire is usually copper or aluminum, and is used for electric motors, generators, transformers, magnets, and related products.

I.G.2. Applicability

This section applies to, but is not limited to, coaters and drying ovens of magnet wire coating operations.

I.G.3. Emission Limitations

	Kg/lc	Lb/gc
Magnetic wire coating operation	0.20	1.7

I.H. Metal Furniture Coating Operations

I.H.1. Definitions

I.H.1.a. "Metal Furniture" means furnishings commonly considered furniture, for domestic, business, and/or institutional use, which have one or more essential, major components made of metal. "Metal furniture" includes, but is not limited to, tables, chairs, wastebaskets, beds, desks, lockers, shelving, cabinets, room dividers, clothing racks, chests of drawers, and sofas.

I.H.1.b. "Metal Furniture Coating" means applying a "surface coating" to "metal furniture" as defined. It excludes coating of non-metal components.

I.H.2. Applicability

This section applies to all metal furniture coating lines.

I.H.3. Emission Limitations

	Kg/lc	Lb/gc
Metal Furniture Coating Line: All coats (including prime, single, and topcoat)	0.36	3.0

I.I. Paper Coating Operations

I.I.1. Definition

"Paper Coating" means impregnating or applying a uniform layer of "surface coating" to paper. It includes, but is not limited to, the production of: coated, glazed, decorated, and varnished paper; carbon and pressure-sensitive copy papers; paper adhesive-labels and tapes; blue-print; photographic and copier paper. It also includes coating of metal foil such as gift wrap and packaging. Paper coating does not include impregnation using a batch dipping process.

I.I.2. Applicability

This section applies to paper coating lines, which includes, but is not limited to, coaters and drying ovens.

I.I.3. Emission Limitations

	Kg/lc	Lb/gc
Paper Coating Line	0.35	2.9

I.J. Plastic-Film Coating Operations

I.J.1. Definition

I.J.1.a. "Plastic-Film Coating" means applying a uniform layer of "surface coating" to a flexible web or sheet of thin plastic substance, excluding all rubbers and vinyl's* (polyvinyl chloride) except for the following two categories of vinyl products: (1) vinyl tapes and (2) vinyl's coated with an adhesive or pressure-sensitive coating. It includes, but is not limited to: plastic typewriter ribbons, photographic film, adhesive tapes, and magnetic recording tapes. (*see Section I.K.)

I.J.2. Applicability

This section applies to, but is not limited to, coaters and drying ovens of plastic-film coating lines.

I.J.3. Emission Limitations

	Kg/lc	Lb/gc
Plastic-Film Coating Line	0.35	2.9

I.K. Vinyl Coating Operations

I.K.1. Definition

"Vinyl Coating" means applying a uniform layer, decorative or protective topcoat to a vinyl (polyvinyl chloride) coated fabric or vinyl sheet. It includes printing of same. Excluded are*: (1) the coating of same with adhesive or pressure-sensitive coatings and (2) vinyl tapes. (*see Section I.J.)

I.K.2. Application

This section applies to vinyl coating lines which includes, but is not limited to, coaters and drying ovens.

I.K.3. Emission Limitations

	Kg/lc	Lb/gc
Vinyl Coating Line	0.45	3.8

I.L. Manufactured Metal Parts and Metal Products

I.L.1. General Provisions

I.L.1.a. Applicability

This section applies to the application area(s), flashoff area(s), oven(s), and drying areas including (but not limited to) air and forced air drier(s) used in the surface coating of the metal parts and products listed below. This section applies to prime coat, top coat, and single coat operations. This section is applicable to surface coating of manufactured metal parts and metal products which include:

- I.L.1.a.(i) Large farm machinery (harvesting, fertilizing, and planting machines, tractors, combines, etc.);
- I.L.1.a.(ii) Small-farm, lawn and garden machinery (lawn and garden tractors, lawn mowers, rototillers, etc.);
- I.L.1.a.(iii) Small appliances (fans, mixers, blenders, crock pots, dehumidifiers, vacuum cleaners, etc.);
- I.L.1.a.(iv) Commercial machinery (office equipment, computers and auxiliary equipment, typewriters, calculators, vending machines, etc.);

- I.L.1.a.(v) Industrial machinery (pumps, compressors, conveyor components, fans, blowers, transformers, etc.);
- I.L.1.a.(vi) Fabricated metal products (metal covered doors, frames, etc.);
- I.L.1.a.(vii) Furniture hardware made of metal for use with non-metal furniture; and
- I.L.1.a.(viii) Any other industrial category which coats metal parts or products under the standard industrial classification code of major group 33 (primary metal industries), major group 34 (fabricated metal products), major group 35 (non-electric machinery), major group 36 (electrical machinery), major group 37 (transportation equipment), major group 38 (miscellaneous instruments), and major group 39 (miscellaneous manufacturing industries), according to the "Standard Industrial Classification Manual" Executive Office of the President, Office of Management and Budget.

I.L.1.b. Exemptions

- I.L.1.b.(i) This Section I.L. is not applicable to the surface coating of the following metal parts and products inasmuch as these are previously covered in Sections I.B., C., D., F., G., and H., respectively:

- I.L.1.b.(i)(A) Automobiles and light-duty trucks
- I.L.1.b.(i)(B) Metal cans
- I.L.1.b.(i)(C) Flat metal sheets and strips in the form of rolls or coils
- I.L.1.b.(i)(D) Large appliances
- I.L.1.b.(i)(E) Magnet wire for use in electrical machinery
- I.L.1.b.(i)(F) Metal furniture

- I.L.1.b.(ii) This Section I.L. is not applicable to the following special purpose coatings:

- I.L.1.b.(ii)(A) Division-approved exemptions for high performance coatings on a case-by-case basis.
- I.L.1.b.(ii)(B) Full exterior repainting of automobiles and light-duty trucks if fewer than 18 vehicles are painted per day.

I.L.1.c. Definitions

For the purpose of this section, the following definitions apply:

- I.L.1.c.(i) "Air Dried Coating" means coatings which are dried by the use of air or forced warm air at temperatures up to 90°C (194°F);

- I.L.1.c.(ii) "Clear Coat" means a coating, which lacks color and opacity or a coating which is transparent;
- I.L.1.c.(iii) "Coating Application System" means all operations and equipment which apply, convey, and dry a surface coating, including, but not limited to, spray booths, flow coaters, flashoff areas, air dryers and ovens;
- I.L.1.c.(iv) "Extreme Environmental Conditions" means exposure to any of the following: temperatures consistently above 95°C, detergents, abrasive and scouring agents, solvents, and corrosive environments;
- I.L.1.c.(v) "Extreme Performance Coatings" means coatings designed for extreme environmental conditions.

I.L.2. Provisions for Specific Processes

I.L.2.a. No owner or operator of a facility or operation engaging in the surface coating of manufactured metal parts or metal products may operate a coating application system subject to this regulation that emits VOC in excess of:

- I.L.2.a.(i) Clear coatings: 0.52 kg/lc (4.3 lb/gc)
- I.L.2.a.(ii) Extreme Performance Coatings: 0.42 kg/lc (3.5 lb/gc)
- I.L.2.a.(iii) Air-Dried Coatings: 0.42 kg/lc (3.5 lb/gc)
- I.L.2.a.(iv) Other coatings and systems: 0.36 kg/lc (3.0 lb/gc) delivered to a coating applicator for all other coatings and coating application systems.

I.L.2.b. If more than one emission limitation in Section I.L.2.a. applies to a specific coating, then the least stringent emission limitation shall be applied.

I.L.2.c. Pioneer Metal Finishing, Inc., a surface coating operation, is authorized pursuant to Regulation Number 3, Part A, Section V. and Regulation Number 7, Part A, Section II.D.1.a. to use up to twenty (20) tons of certified emission reduction credits of volatile organic compounds (VOC) as an alternative compliance method to satisfy the surface coating emission limitations of Regulation Number 7 in accordance with and upon demonstration of the conditions set forth below:

- I.L.2.c.(i) Certified emission reduction credits for VOCs (methanol) to be used in this transaction were formerly owned by the Coors Brewing Company, registered and issued in Emissions Reduction Credit Permit 91AR120R on July 25, 1994;
- I.L.2.c.(ii) Those emission reduction credits were originally obtained by Coors from Verticel, a company that produced honeycomb packaging material and was located within five miles of the PMF facility;

- I.L.2.c.(iii) The use of these VOC emission reduction credits identified above shall be used to satisfy VOC limitations of certain specified surface coatings in excess of Control Technique Guidance as specified in Regulation Number 7, Section I.L.2.a. and Section I.A.6.b., and applicable to the Pioneer Metal finishing operations;
- I.L.2.c.(iv) Such emission reduction credits identified above will be used by PMF to achieve compliance with Regulation Number 7 to compensate for ozone precursor emission of VOCs from non-compliant coatings which meet the emission trading requirements of Regulation Number 3, Part A, Section V. In order to satisfy the photochemical reactivity equivalency requirement of VOC trades, the methanol VOC ERCs will be reduced on a ratio of 1.1:1 for VOCs of toluene, ethylbenzene, xylene and ketones emitted from non-compliant coatings. All other VOCs involved in this transaction are considered to be of the same degree of photochemical reactivity;
- I.L.2.c.(v) The requirement in Regulation Number 3, Part A, Section V.F.2. shall not apply to this transaction;
- I.L.2.c.(vi) This transaction is only valid within the Denver/Boulder nonattainment area as described at 40 CFR 81, Subchapter C - Air Programs, Subpart C, Section 107 - Attainment Status Designations, Section 81.306 (February 16, 1995);
- I.L.2.c.(vii) This transaction shall be calculated upon a pound for pound basis and averaged over a maximum 24-hour period.
- I.L.2.c.(viii) This transaction shall be effective upon approval by the U.S. Environmental Protection Agency as a revision to the Colorado State Implementation Plan and after issuance of a State Construction Permit incorporating, but not limited to, the conditions and requirements of the Section;
- I.L.2.c.(ix) This transaction may not be used to satisfy any current or future requirements of NSPS, BACT, LAER, or MACT requirements of HAPs which may apply to PMF, except that this transaction may be used to satisfy control technique guidance or RACT requirements contained in Regulation Number 7 which are applicable to PMF;
- I.L.2.c.(x) This transaction shall not interfere with any applicable requirement concerning attainment and reasonable further progress in the Colorado State Implementation Plan or any other applicable requirements of the Clean Air Act;
- I.L.2.c.(xi) This transaction shall be registered and enforced through a State Construction Permit issued to Pioneer Metal Finishing, Inc. containing, but not limited to the conditions and limitations set forth in this Section;

- I.L.2.c.(xii) Such state Construction Permit issued to Pioneer Metal Finishing, Inc. shall specify, among other, things the necessary monitory, recordkeeping and reporting requirements to insure that the emission reduction credits are applied in accordance with the conditions and requirements of this Section;
- I.L.2.c.(xiii) The state Construction Permit shall allow a daily maximum limitation of 160 lbs. of VOC emissions from non-compliant surface coatings and an annual limitation of 40,000 lbs. of non-compliant VOC emissions. The annual limitation shall be calculated on a 12-month rolling total calculated on the first day of each month using the previous 12 months.
- I.L.2.c.(xiv) The state Construction Permit shall limit the VOC-HAP emissions to less than ten (10) per year of any one HAP or twenty-five (25) tons per year of any combination of HAP emissions; and
- I.L.2.c.(xv) PMF will maintain records of daily and monthly totals of non-compliant surface coatings used in its operation and report such usages on an annual basis to the Division or as otherwise requested.

I.M. Flat Wood Paneling Coating.

I.M.1. Definitions

- I.M.1.a. "Class II Hardboard Paneling Finish" means finishes which meet the specifications of Voluntary Product Standard PS-59-73 as approved by the American National Standards Institute.
- I.M.1.b. "Coating Application System" means all operations and equipment which apply, convey, and dry a surface coating, including, but not limited to, spray booths, flow coaters, conveyers, flashoff areas, air dryers and ovens.
- I.M.1.c. "Hardboard" is a panel manufactured primarily from inter-felted ligno-cellulosic fibers which are consolidated under heat and pressure in a hot press.
- I.M.1.d. "Hardboard Plywood" is plywood whose surface layer is a veneer of hardwood.
- I.M.1.e. "Natural Finish Hardwood Plywood Panels" means panels whose original grain pattern is enhanced by essentially transparent finishes frequently supplemented by fillers and toners.
- I.M.1.f. "Printed Interior Panels" means panels whose grain or natural surface is obscured by fillers and basecoats upon which a simulated grain or decorative pattern is printed.
- I.M.1.g. "Thin Particleboard" is a manufactured board 1/4 inch or less in thickness made of individual wood particles which have been coated with a binder and formed into flat sheets by pressure.
- I.M.1.h. "Tileboard" means paneling that has a colored waterproof surface coating.

I.M.2. Applicability

This section applies to all flat wood manufacturing and surface finishing facilities that manufacture printed interior panels made of hardwood plywood and thin particle board; natural finish hardwood plywood panels, or hardboard paneling with Class II finishes. This section does not apply to the manufacture of exterior siding, tileboard, or particleboard used as a furniture component.

I.M.3. Emission Limitations

I.M.3.a. 2.9 kg per 100 square meters of coated finished product (6.0 lb/1,000 sq. ft.) from printed interior panels, regardless of the number of coats applied;

I.M.3.b. 5.8 kg per 100 square meters of coated finished product (12.0 lb/1,000 sq. ft.) from natural finish hardwood plywood panels, regardless of the number of coats applied; and

I.M.3.c. 4.8 kg per 100 square meters of coated finished product (10.0 lb/1,000 sq. ft.) from Class II finishes on hardboard panels, regardless of the number of coats applied.

I.N. Manufacture of Pneumatic Rubber Tires

I.N.1. Definitions

I.N.1.a. "Bead Dipping" means the dipping of an assembled tire bead into a solvent-based cement.

I.N.1.b. "Green Tires" means assembled tires before holding and curing have occurred.

I.N.1.c. "Green Tire Spraying" means the spraying of green tires, both inside and outside, with release compounds which help remove air from the tire during molding and prevent the tire from sticking to the mold after curing.

I.N.1.d. "Pneumatic Rubber Tire Manufacture" means the production of pneumatic rubber, passenger type tires on a mass production basis.

I.N.1.e. "Passenger Type Tire" means agricultural, airplane, industrial, mobile home, light and medium duty truck, and passenger vehicle tires with a bead diameter up to 20.0 inches and cross section dimension up to 12.8 inches.

I.N.1.f. "Tread End Cementing" means the application of a solvent-based cement to the tire tread ends.

I.N.1.g. "Undertread Cementing" means the application of a solvent-based cement to the underside of a tire tread.

I.N.1.h. "Water Based Sprays" means release compounds, sprayed on the inside and outside of green tires, in which solids, water, and emulsifiers have been substituted for organic solvents.

I.N.2. Applicability

This section applies to VOC emissions from the following operations in all pneumatic rubber tire facilities: undertread cementing, tread end cementing, bead dipping, and green tire spraying.

The provisions of this section do not apply to the production of specialty tires for antique or other vehicles when produced on an irregular basis or with short production runs. This exemption applies only to tires produced on equipment separate from normal production lines for passenger type tires.

I.N.3. Provisions for Specific Processes

I.N.3.a. The owner or operator of an undertread cementing, tread end cementing, or bead dipping operation subject to this regulation shall:

I.N.3.a.(i) Install and operate a capture system, designed to achieve maximum reasonable capture, up to 85 percent by weight of VOC emitted, from all undertread cementing, tread end cementing and bead dipping operations. Maximum reasonable capture shall be consistent with the following documents:

I.N.3.a.(i)(A) Industrial Ventilation, A Manual of Recommended Practices, 17th Edition, American Federation of Industrial Hygienists, 1982.

I.N.3.a.(i)(B) Recommended Industrial Ventilation Guidelines, U.S. Department of Health, Education and Welfare, National Institute of Occupational Safety and Health, January 1976.

I.N.3.a.(ii) Install and operate a control device that meets the requirements of one of the following:

I.N.3.a.(ii)(A) A carbon adsorption system designed and operated in a manner such that there is at least a 95.0 percent removal of VOC by weight from the gases ducted to the control device; or,

I.N.3.a.(ii)(B) An incineration system that oxidizes at least 90.0 percent of the nonmethane volatile organic compounds (VOC measured as total combustible carbon) which enter the incinerator to carbon dioxide and water.

I.N.4. The owner or operator of a green tire spraying operation subject to this regulation must implement one of the following means of reducing volatile organic compound emissions:

I.N.4.a. Substitute water-based sprays for the normal solvent-based mold release compound; or,

I.N.4.a.(i) Install a capture system designed and operated in a manner that will capture and transfer at least 90.0 percent of the VOC emitted by the green tire spraying operation to a control device; and,

I.N.4.a.(ii) In addition to Section I.N.4.a.(i), install and operate a control device that meets the requirements of one of the following:

I.N.4.a.(ii)(A) a carbon adsorption system designed and operated in a manner such that there is at least 95.0 percent removal of VOC by weight from the gases ducted to the control device; or,

I.N.4.a.(ii)(B) an incineration system that oxidizes at least 90 percent of the nonmethane volatile organic compounds (VOC measured as total combustible carbon) to carbon dioxide and water.

I.N.5. Testing of capture system efficiency shall meet the requirements of Section I.A.5.e.

I.N.6. Control devices shall meet the applicable requirements, including recordkeeping, of Sections I.A.3.a., b., c., and e., and I.A.8.a. and b.

I.N.7. The applicable EPA reference methods 1 through 4, and 25, of 40 CFR Part 60 (September 14, 1989), shall be used to determine the efficiency of control devices.

I.O. Wood Products Coating

I.O.1. Definitions

I.O.1.a. "As Applied" means the VOC and solids content of the finishing material that is actually used for coating the substrate. It includes the contribution of materials used for in-house dilution of the finishing material.

I.O.1.b. "Cleaning Operation" means operations in which organic solvent is used to remove coating materials from equipment used in wood furniture manufacturing operations.

I.O.1.c. "Conventional Air Spray" means a spray coating method in which the coating is atomized by mixing it with compressed air at an air pressure greater than 10 pounds per square inch (gauge) at the point of atomization. Airless and air assisted spray technologies are not conventional air spray because the coating is not atomized by mixing it with compressed air. Electrostatic spray technology is also not considered conventional air spray because an electrostatic charge is employed to attract the coating to the workplace.

I.O.1.d. "Equipment Leak" means emissions of VOCs from pumps, valves, flanges, or other equipment used to transfer or apply finishing materials or organic solvents.

I.O.1.e. "Finishing Material" means a coating used in the wood furniture industry including, but not limited to, basecoats, stains, washcoats, sealers, and topcoats.

I.O.1.f. "Finishing Operation" means those activities in which a finishing material, including, but not limited to, basecoats, stains, washcoats, sealers, and topcoats, is applied to a substrate and is subsequently air-dried, cured in an oven, or cured by radiation.

- I.O.1.g. "Organic Solvent" means a liquid containing VOCs that is used for dissolving or dispersing constituents in a coating, adjusting the viscosity of a coating, cleaning, or washoff. When used in a coating, the organic solvent evaporates during drying and does not become part of the dried film.
- I.O.1.h. "Sealer" means a finishing material used to seal the pores of a wood substrate before additional coats of finishing material are applied. Washcoats, which are used in some finishing systems to optimize aesthetics, are not sealers.
- I.O.1.i. "Strippable Booth Coating" means a coating that is applied to a booth wall to provide a protective film to receive overspray during finishing operations that is subsequently peeled off and disposed, and reduces or eliminates the need to use organic solvents to clean booth walls.
- I.O.1.j. "Topcoat" means the last film-building finishing material applied in a finishing system. Non-permanent final finishes are not topcoats.
- I.O.1.k. "Washcoat" means a transparent special purpose coating that has a solids content by weight of 12 percent or less. Washcoats are applied over initial stains to protect and control color and to stiffen the wood fibers in order to aid sanding.
- I.O.1.l. "Washoff Operation" means those operations in which organic solvent is used to remove coating from a substrate.
- I.O.1.m. "Wood Furniture" means any product made of wood, a wood product such as rattan or wicker, or an engineer wood product such as particleboard.
- I.O.1.n. "Wood Furniture Component" means any part that is used in the manufacture of wood furniture including, but not limited to, drawer sides, cabinet doors, seat cushions, and laminated tops.
- I.O.1.o. "Wood Furniture Manufacturing Operation" means the finishing, cleaning, and washoff operations associated with the production of wood furniture or wood furniture components.

I.O.2. Applicability

This section applies to wood furniture manufacturing operations with uncontrolled actual VOC emissions greater than or equal to 25 tons per calendar year.

Beginning July 1, 2021, this section applies to other wood products coating operations with uncontrolled actual VOC emissions greater than or equal to 50 tons per year (as of January 27, 2020, located in the 8-Hour Ozone Control Area).

I.O.3. Emission Limitations

I.O.3.a. The owner or operator of a wood furniture manufacturing or other wood products coating operation must limit VOC emissions from finishing operations by:

- I.O.3.a.(i) Using topcoats with a VOC content equal to or less than 0.8 lb VOC/lb solids (0.8 kg VOC/kg solids); or
- I.O.3.a.(ii) Using a finishing system of:

- I.O.3.a.(ii)(A) Sealers with a VOC content equal to or less than 1.9 lb VOC/lb solids (1.9 kg VOC/kg solids), as applied; and
- I.O.3.a.(ii)(B) Topcoats with a VOC content equal to or less than 1.8 lb VOC/lb solids (1.8 kg VOC/kg solids), as applied; or
- I.O.3.a.(iii) For sources using acid-cured alkyd amino vinyl sealers or acid-cured alkyd amino conversion varnish topcoats:
 - I.O.3.a.(iii)(A) Use acid-cured alkyd amino vinyl sealers with a VOC content equal to or less than 2.3 lb VOC/lb solids (2.3 kg VOC/kg solids), as applied, and an acid-cured alkyd amino conversion varnish topcoat with a VOC content equal to or less than 2.0 lb VOC/lb solids (2.0 kg VOC/kg solids), as applied; or
 - I.O.3.a.(iii)(B) Use acid-cured alkyd amino conversion varnish topcoat with a VOC content equal to or less than 2.0 lb VOC/lb solids (2.0 kg VOC/kg solids), as applied, and sealers with a VOC content equal to or less than 1.9 lb VOC/lb solids (1.9 kg VOC/kg solids); or
 - I.O.3.a.(iii)(C) Use acid-cured alkyd amino vinyl sealers with a VOC content equal to or less than 2.3 lb VOC/lb solids (2.3 kg VOC/kg solids), as applied, and topcoats with a VOC content equal to or less than 1.8 lb VOC/lb solids (1.8 kg VOC/kg solids), as applied.
- I.O.3.b. The owner or operator of a wood furniture manufacturing or other wood products coating operation must use strippable booth coatings with a VOC content equal to or less than 0.8 lb VOC/lb solids (0.8 kg VOC/kg solids), as applied.
- I.O.3.c. The owner or operator of a wood furniture manufacturing or other wood products coating operation must use compounds containing equal to or less than 8.0 percent by weight of VOC for cleaning spray booth components other than conveyors, continuous coaters and their enclosures, and/or metal filters, unless the spray booth is being refurbished. If the spray booth is refurbished (i.e., spray booth coating or other material used to cover the booth is being replaced), the owner or operator must use equal to or less than 1.0 gallon of organic solvent to prepare the booth prior to applying the booth coating.

I.O.4. Work Practices

- I.O.4.a. In addition to complying with Sections I.A.7. and I.A.9., the owner or operator of a wood furniture manufacturing or other wood products coating operation must:
 - I.O.4.a.(i) Develop an operator training program that includes, at a minimum, appropriate application techniques, appropriate cleaning and washoff procedures, appropriate equipment setup and adjustment to minimize finishing material usage and overspray, and appropriate management of cleanup wastes;

- I.O.4.a.(ii) Conduct monthly visual inspections of all equipment used to transfer or apply finishing materials or organic solvents for equipment leaks and repair equipment leaks within 15 working days, or within 3 months if the leaking equipment must be replaced by a new purchase;
- I.O.4.a.(iii) Collect cleaning and washoff solvents into closed containers;
- I.O.4.a.(iv) Use conventional air spray guns only to:
 - I.O.4.a.(iv)(A) Apply finishing materials with a VOC content equal to or less than 1.0 lb VOC/lb solids (1.0 kg VOC/kg solids), as applied;
 - I.O.4.a.(iv)(B) Touch-up and repair after completion of the finishing operation, after stain and before other finishing material, or to apply stain on a part for which it is technically or economically infeasible to use any other spray application technology.

I.O.5. Recordkeeping

I.O.5.a. The owner or operator of a wood furniture manufacturing or other wood products coating operation must keep the following records for five (5) years and make them available for inspection by the Division upon request:

- I.O.5.a.(i) Records of calendar year VOC emission estimates demonstrating whether the wood furniture manufacturing operation means or exceeds the applicability threshold in Section I.O.2.;
- I.O.5.a.(ii) Records of the operator training program;
- I.O.5.a.(iii) Records of the date and results of the monthly equipment inspections and any repairs that were made;
- I.O.5.a.(iv) Records such as, but not limited to, data sheets documenting how the as applied values were determined and safety data sheets or other analytical data from the manufacturer showing the VOC content of each sealer, topcoat, strippable booth coating, or cleaning booth compound subject to the emission limits in Section I.O.3.; and
- I.O.5.a.(v) Monthly records of the quantity and type of organic cleaning and washoff solvent used.

II. Solvent Use

II.A. General Provisions

II.A.1. Applicability

The provisions of this section apply to cold cleaners, non-conveyorized vapor degreasers, conveyorized degreasers, industrial cleaning solvent operations, and other operations that use

solvents. Open top vapor degreasers are a subset of non-conveyorized vapor degreasers. The owner or operator of a unit subject to this section shall ensure that no such unit is used unless the requirements of this section are satisfied. Section II.E. requirements are effective on January 1, 2017. Section II.F. requirements are effective on May 1, 2021.

II.A.2. Definitions

II.A.2.a. "Cold-Cleaner" means a container of non-aqueous liquid solvent held below its boiling point, which is designed, used, or intended for cleaning solid objects in a batch-loaded process. A "cold-cleaner" may have provisions for heating the solvent. It does not include vapor degreasers or continuously loaded conveyorized degreasers.

II.A.2.b. "Composite Partial Vapor Pressure" means the sum of the partial pressures of the compounds defined as VOCs. Composite partial vapor pressure is calculated as follows:

$$PP_c = \sum_{i=1}^n \frac{(W_i)(VP_i)/MW_i}{\frac{W_w}{MW_w} + \sum_{c=1}^n \frac{W_c}{MW_c} + \sum_{i=1}^n \frac{W_i}{MW_i}}$$

Where:

W_i = Weight of the "i"th VOC compound, in grams
 W_w = Weight of water, in grams
 W_e = Weight of exempt compound, in grams
 MW_i = Molecular weight of the "i"th VOC compound, in g/g-mole
 MW_w = Molecular weight of water, in g/g-mole
 MW_c = Molecular weight of exempt compound, in g/g-mole
 PP_c = VOC composite partial vapor pressure at 20°C (68°F), in mm Hg
 VP_i = Vapor pressure of the "i"th VOC compound at 20°C(68°F), in mm Hg

II.A.2.c. "Conveyorized Degreaser" means an apparatus that performs degreasing or other cleaning functions through the use of non-aqueous liquid solvent and/or solvent vapors within a container, and which has a conveyor mechanism allowing continuous loading of items conveyed into and out of the solvent.

II.A.2.d. "Freeboard" in a vapor degreaser means the vertical distance from the top of the vapor zone (as established by normal operations within the specifications of the degreaser manufacturer) to the top of the degreaser. For cold-cleaners "freeboard" means the vertical distance from the surface of the solvent liquid to the top of the degreaser. If all sides are not even, the vertical distance to the top of the lowest side shall be used to make the determination of freeboard.

II.A.2.e. "Freeboard Ratio" means the ratio of the freeboard to the width of the solvent surface.

II.A.2.f. "Industrial Cleaning Solvent" means a VOC-containing liquid used to perform industrial cleaning solvent operations.

II.A.2.g. "Industrial Cleaning Solvent Operation" means the use of an industrial cleaning solvent for cleaning industrial operations such as spray gun cleaning, spray booth cleaning, large manufactured parts cleaning, equipment cleaning, floor cleaning, line cleaning, parts cleaning, tank cleaning, and small manufactured parts cleaning. Residential and janitorial cleaning are not considered industrial cleaning solvent operations.

II.A.2.h. "Non-Conveyorized Vapor Degreaser" means an apparatus, which uses non-aqueous solvent vapors within some type of container to degrease or otherwise clean solid objects in a batch-loaded process. It excludes continuously loaded conveyorized degreasers.

II.A.2.i. "Residential and Janitorial Cleaning" means the cleaning of a building or building components including, but not limited to, floors, ceilings, wall, windows, doors, stairs, bathrooms, furnishings, and exterior surfaces of office equipment, excluding the cleaning of work areas where manufacturing or repair activity is performed.

II.A.2.j. "Solvent Metal Cleaning" means the process of cleaning soils from metal surfaces by cold cleaning, conveyorized degreasing, or non-conveyorized vapor degreasing.

II.A.3. Transfer of waste solvent and used solvent

In any disposal or transfer of waste or used solvent, at least 80 percent by weight of the solvent/waste liquid shall be retained (i.e., no more than 20 percent of the liquid solvent/solute mixture shall evaporate or otherwise be lost during transfers).

II.A.4. Storage of waste solvent and used solvent

Waste or used solvent shall be stored in closed containers unless otherwise required by law.

II.A.5. Any control device shall meet the applicable requirements of Sections I.A.3.a., b., c., e., and I.A.8.a. and b.

II.B. Control of Solvent Cold-Cleaners

II.B.1. Control Equipment

II.B.1.a. Covers

II.B.1.a.(i) All cold-cleaners shall have a properly fitting cover.

II.B.1.a.(ii) Covers shall be designed to be easily operable with one hand under any of the following conditions:

II.B.1.a.(ii)(A) Solvent true vapor pressure is greater than 15 torr (0.3 psia) at 38°C (100°F).

II.B.1.a.(ii)(B) The solvent is agitated by an agitating mechanism.

II.B.1.a.(ii)(C) The solvent is heated.

II.B.1.b. Drainage Facility

- II.B.1.b.(i) All cold-cleaners shall have a drainage facility that captures the drained liquid solvent from the cleaned parts.
- II.B.1.b.(ii) For cold-cleaners using solvent which has a vapor pressure greater than 32 torr (0.62 psia) measured at 38°C (100°F) either:

- II.B.1.b.(ii)(A) There shall be an internal drainage facility within the confines of the cold-cleaner, so that parts are enclosed under the (closed) cover to drain after cleaning, or if such a facility will not fit within;

- II.B.1.b.(ii)(B) An enclosed, external drainage facility that captures the drained solvent liquid from the cleaned parts.

II.B.1.c. A permanent, clearly visible sign shall be mounted on or next to the cold-cleaner. The sign shall list the operating requirements.

II.B.1.d. Solvent spray apparatus shall not have a splashing, fine atomizing, or shower type action but rather should produce a solid, cohesive stream. Solvent spray shall be used at a pressure that does not cause excessive splashing.

For solvents with a true vapor pressure above 32 torr (0.62 psia) at 38°C (100°F), or, for solvents heated above 50°C (120°F), one of the following techniques shall be used:

- II.B.1.d.(i) A freeboard ratio greater than or equal to 0.7.

- II.B.1.d.(ii) A water or a non-volatile liquid cover. The cover liquid shall not be soluble in the solvent and shall not be denser than the solvent and the depth of the cover liquid shall be sufficient to prevent the escape of solvent vapors.

II.B.2. Operating requirements

II.B.2.a. The cold-cleaner cover shall be closed whenever parts are not being handled within the cleaner confines.

II.B.2.b. Cleaned parts shall be drained for at least 15 seconds and/or until dripping ceases. Any pools of solvent shall be tipped out on the clean part back into the tank.

II.C. Control of Non-Conveyorized Vapor Degreasers

II.C.1. Control Equipment

II.C.1.a. The non-conveyorized vapor degreaser shall have a cover which shall be designed and operated so that it can be easily opened and closed through the use of mechanical assists such as spring loading, counterweights, etc.; opening and closing the cover shall not disturb the vapor zone.

II.C.1.b. Safety Switches

The following two types of switches shall be installed on vapor degreasers:

II.C.1.b.(i) Condenser flow switch and thermostat - (shuts off sump heat if the condenser coolant is either not circulating or is too warm); and

II.C.1.b.(ii) Spray safety switch - (shuts off spray pump if the vapor level drops more than four (4) inches).

II.C.1.c. Control Device

II.C.1.c.(i) For non-conveyorized vapor degreasers with an open area (with the cover open) of one square meter (10.8 ft²) or less, either the freeboard ratio shall be greater than or equal to 0.75, or one of the control devices in II.C.1.c.(ii) shall be used.

II.C.1.c.(ii) For non-conveyorized vapor degreasers with an open area (with the cover open) greater than one (1) square meter, (10.8 ft²), at least one of the following control systems shall be used:

II.C.1.c.(ii)(A) Both a powered cover and a freeboard ratio greater than or equal to 0.75.

II.C.1.c.(ii)(B) A refrigerated chiller with a cooling capacity equivalent to or greater than the applicable specifications in Appendix C.

II.C.1.c.(ii)(C) An enclosed design: A system where the cover(s) or door(s) opens only when a dry part is entering or exiting the degreaser.

II.C.1.c.(ii)(D) A carbon adsorption system with ventilation greater than or equal to 15 cubic meters each minute per square meter (50 cfm/ft²) of air/vapor area (when the cover(s) is [are] open), exhausting less than 25 parts per million (by volume) of solvent averaged over one complete adsorption cycle.

II.C.1.d. A permanent, clearly visible sign shall be mounted on or next to the degreaser. The sign shall list the operating requirements.

II.C.2. Operating Requirements

II.C.2.a. Keep cover closed at all times except when processing work loads into or out of the degreaser.

II.C.2.b. The following operations shall be performed to minimize solvent carry-out:

II.C.2.b.(i) Rack parts to allow full drainage.

II.C.2.b.(ii) Move parts as slowly as is practicable in and out of the degreaser. A maximum of one foot every five seconds by hand or a maximum of 5.5 cm/sec. (10.8ft/min) for a mechanically operated system.

II.C.2.b.(iii) Allow the workload to clean in the vapor zone at least 30 seconds or until condensation ceases.

II.C.2.b.(iv) Tip out any pools of solvent that remain on the cleaned parts before removal from the vapor zone.

II.C.2.b.(v) Allow parts to dry within the degreaser at least 15 seconds and/or until visually dry.

II.C.2.c. Solvents shall not be used to clean porous or absorbent materials; for example, cloth, leather, wood, rope, etc.

II.C.2.d. Workloads shall not occupy more than half of the degreaser's open top area.

II.C.2.e. Spraying shall not be done above the vapor level.

II.C.2.f. Solvent leaks shall be repaired immediately, or the degreaser shall be shut down.

II.C.2.g. Exhaust ventilation shall not exceed twenty (20) cubic meters per minute per square meter (65.6 cfm per sq. ft.) of degreaser open area, unless greater exhaust rates are necessary to meet Occupational and Safety Health Act requirements. Ventilation fans shall not be used near the degreaser opening, unless necessary to meet Occupational and Safety Health Act requirements.

II.C.2.h. The water separator shall function so that no visible water is present in the solvent exiting the separator.

II.D. Control of Conveyorized Degreasers

II.D.1. Control Equipment

II.D.1.a. Control Device

For all conveyorized degreasers with a solvent surface area greater than two (2) square meters (21.5 square feet), the degreasing shall be controlled by at least one of the following:

II.D.1.a.(i) Carbon adsorption system, with ventilation greater or equal to 15 cubic meters per minute per square meter (49.2 cfm/ft²) of air/vapor interface for vapor degreasers (of air/liquid interface for non-vapor types) when down-time covers are open, and exhausting less than 25 parts per million of solvent (by volume) averaged over a complete adsorption cycle.

II.D.1.a.(ii) For vapor degreasers only: a refrigerated chiller with a cooling capacity equivalent to or greater than the applicable specifications in Appendix D.

II.D.1.b. Prevention of Carry-out

A drying tunnel, tumbling basket(s), or other demonstrably effective method(s) shall be employed to prevent cleaned parts from carrying out solvent liquid or vapor.

II.D.1.c. Safety Switches

II.D.1.c.(i) The following two (2) switch-circuits (or equivalent) shall be installed.

II.D.1.c.(i)(A) A spray safety switch shall shut off the spray pump and/or the conveyor if the vapor level drops more than four (4) inches.

II.D.1.c.(i)(B) A vapor level control thermostat shall shut off sump heat when the vapor level rises too high.

II.D.1.c.(ii) All conveyorized degreasers shall have a condenser thermostat and flow-detector switch (or equivalent) which shuts off sump heat if coolant is too warm or is not circulating.

II.D.1.d. Minimized Openings: Degreaser entrance and exit openings shall silhouette workloads so that the average clearance between parts (or parts-and the edge of the degreaser opening) is either:

II.D.1.d.(i) less than 10 centimeters (4 inches) or;

II.D.1.d.(ii) less than 10 percent of the width of the opening

II.D.1.e. Covers shall be provided to close off all the entrance(s) and exit(s) when the conveyor is not in use.

II.D.1.f. A permanent, clearly visible sign shall be mounted on or next to the degreaser. The sign shall list the operating requirements.

II.D.2. Operating Requirements

II.D.2.a. Exhaust ventilation shall not exceed 20 m³/minute per square meter of degreaser opening (65.6 cf/m per square foot), unless necessary to meet OSHA requirements. Work place fans shall not be located near, nor directed at degreaser openings, unless necessary to meet OSHA requirements. Exhaust flow shall be measured by EPA reference methods 1 and 2 of 40 CFR Part 60 (September 14, 1989).

II.D.2.b. Carry-out emissions shall be minimized by:

II.D.2.b.(i) Racking parts in such a manner to achieve best drainage.

II.D.2.b.(ii) Maintaining the vertical component of conveyor speed at less than 3.3 meters per minute (10.8 feet per minute).

II.D.2.c. Repair solvent leaks immediately, or shut down the degreaser.

II.D.2.d. The water separator shall function with an efficiency sufficient to prevent water from being visible in the solvent exiting the separator.

II.D.2.e. Down-time cover(s) shall be placed over entrances and exits of conveyorized degreasers immediately after the conveyor and exhaust are shut down. Covers shall be retained in position until immediately before start-up.

II.E. Control of Industrial Cleaning Solvent Operations

II.E.1. Control Requirements

The owner or operator of an industrial cleaning solvent operation with total combined uncontrolled actual VOC emissions equal to or greater than three (3) tons per calendar year (excluding VOC emissions from solvents used for cleaning operations that are exempt under Section II.E.4.) must:

- II.E.1.a. Limit the VOC content of cleaning solvents to less than or equal to 0.42 lb of VOC/gal (50 grams VOC/liter); or
- II.E.1.b. Limit the composite partial vapor pressure of the cleaning solvent to 8 millimeters of mercury (mmHg) at 20 degrees Celsius (68 degrees Fahrenheit); or
- II.E.1.c. Reduce VOC emissions with an emission control system having a control efficiency of 90% or greater.

II.E.2. Work Practice Requirements

The owner or operator of an industrial cleaning solvent operation must implement the following work practice requirements at all times to reduce VOC emissions from fugitive sources:

- II.E.2.a. Cover open containers and used applicators in a manner that minimizes evaporation into the atmosphere;
- II.E.2.b. Properly dispose of used solvent and shop towels; and
- II.E.2.c. Implement good air pollution control practices that minimize emissions, including, but not limited to, using only volumes necessary for cleaning and maintaining cleaning equipment to be leak free.

II.E.3. Monitoring, Recordkeeping and Reporting Requirements

II.E.3.a. The owner or operator of an industrial cleaning solvent operation must keep the following records for two (2) years and make them available for inspection by the Division upon request:

- II.E.3.a.(i) If applicable, records demonstrating that a listed exemption to this Section II.E. applies.
- II.E.3.a.(ii) If applicable, monthly records such as safety data sheets or other analytical data from the industrial cleaning solvent manufacturer showing the VOC type and VOC content, or the composite partial vapor pressure at 20 degrees Celsius, and total amount of VOC-containing solvent used in solvent cleaning operations to demonstrate compliance with the control requirements in Sections II.E.1.a. and II.E.1.b.
- II.E.3.a.(iii) If applicable, monthly records sufficient to demonstrate compliance with the control requirement in Section II.E.1.c.
- II.E.3.a.(iv) Records of calendar year VOC emission estimates demonstrating whether the industrial cleaning solvent operation meets or exceeds the applicability threshold in Section II.E.1.

II.E.3.b. Compliance with the control requirements in Section II.E.1. must be demonstrated using one of the following methods as applicable:

- II.E.3.b.(i) Safety data sheets or other analytical data from the industrial cleaning solvent manufacturer to demonstrate compliance with Sections II.E.1.a. and II.E.1.b.;
- II.E.3.b.(ii) A manufacturer guarantee of the control equipment's emission control efficiency and operation and maintenance of control equipment according to manufacturer's specifications to demonstrate compliance with Section II.E.1.c.; or
- II.E.3.b.(iii) A performance test conducted during representative operations using one of the following methods, as applicable:
 - II.E.3.b.(iii)(A) EPA Method 24 (40 CFR Part 60, Appendix A) (November 17, 2016) to determine VOC content;
 - II.E.3.b.(iii)(B) EPA Method 18, 25, or 25A (40 CFR Part 60, Appendix A) (November 17, 2016) to determine control efficiency of the emission control equipment.

II.E.4. Exemptions

II.E.4.a. Industrial cleaning solvent operations are not subject to Section II.E. if they are subject to a work practice or emission control requirement in another federally enforceable section of Regulation Number 7 that establishes RACT.

II.E.4.b. The VOC control requirements in Section II.E.1. do not apply to:

- II.E.4.b.(i) Cleaning of electrical and electronic components;
- II.E.4.b.(ii) Cleaning of precision optics;
- II.E.4.b.(iii) Cleaning of numismatic dies;
- II.E.4.b.(iv) Stripping of cured inks, coatings, and adhesives;
- II.E.4.b.(v) Cleaning of resin, coating, ink, and adhesive manufacturing, mixing, molding, and application equipment;
- II.E.4.b.(vi) Cleaning of research and development laboratories;
- II.E.4.b.(vii) Cleaning of medical device or pharmaceutical manufacturing equipment;
- II.E.4.b.(viii) Performance testing to determine coating, adhesive, ink or ink performance;
- II.E.4.b.(ix) Cleaning of equipment and materials used in testing for quality control or quality assurance purposes;
- II.E.4.b.(x) Cleaning of digital printing operations; and
- II.E.4.b.(xi) Cleaning of screen printing operations.

II.E.4.c. In lieu of compliance with Section II.E.1. and II.E.2., the owner or operator of an area source aerospace facility, as defined in 40 CFR Part 63, Section 63.742

(November 17, 2016), may implement the solvent cleaning provisions of the National Emission Standards for Hazardous Air Pollutants for Aerospace Manufacturing and Rework facilities contained in 40 CFR Part 63, Section 63.744 (November 17, 2016) along with the applicable definitions contained in 40 CFR Part 63, Section 63.742 (November 17, 2016), except that:

- II.E.4.c.(i) VOC-containing solvents which meet the definition of “non-HAP materials” in 40 CFR Part 63, Section 63.742 (November 17, 2016) are not excluded from the housekeeping measures contained in 40 CFR Part 63, Section 63.744(a) (November 17, 2016); and
- II.E.4.c.(ii) The baseline reduction compliance option contained in 40 CFR Part 63, Section 63.744(b)(3) (November 17, 2016) is not available for purposes of compliance with this VOC control rule.

II.F. General Solvent Use

II.F.1. Applicability

II.F.1.a. Within the 8-Hour Ozone Control Area: As of May 1, 2021, the requirements of Section II.F. apply to operations that use solvents with uncontrolled actual VOC emissions greater than or equal to two (2) tons per year that existed at major sources of VOC (greater than or equal to 50 tpy VOC) as of [EFFECTIVE DATE OF THE RECLASSIFICATION].

II.F.1.b. (State Only) Outside the 8-Hour Ozone Control Area: As of May 1, 2021, the requirements of Section II.F. apply to operations that use solvents with uncontrolled actual VOC emissions greater than or equal to five (5) tons per year that existed at sources of VOC greater than or equal to 50 tpy VOC as of [EFFECTIVE DATE OF THE RECLASSIFICATION].

II.F.2. Exemptions

The requirements of this Section II.F. do not apply to:

II.F.2.a. Operations that are subject to a solvent work practice or emission control requirement in another federally enforceable section of Regulation Number 7 that constitutes RACT, or;

II.F.2.b. Solvent use where the solvent does not contain VOCs.

II.F.3. Work practice requirements

The owner or operator of operations that use solvents must implement the following work practice requirements at all times to reduce VOC emissions from fugitive sources:

II.F.3.a. Cover open containers and used applicators in a manner that minimizes evaporation into the atmosphere;

II.F.3.b. Properly dispose of used solvent and solvent contaminated waste (e.g. shop towels and carbon filtration or other control device media), and;

II.F.3.c. Implement good air pollution control practices that minimize emissions, including but not limited to:

- II.F.3.c.(i) Using low or no-VOC solvents, if possible;
- II.F.3.c.(ii) Using only volumes of solvent necessary for operations;
- II.F.3.c.(iii) Using submerged fill pipes in storage tanks and containers;
- II.F.3.c.(iv) Using closed loop systems to minimize solvent loss during transfer and use of solvents;
- II.F.3.c.(v) Maintaining solvent storage, transfer, and use operations equipment in such a way that it minimizes evaporation loss and remains leak free, and;
- II.F.3.c.(vi) Owners or operators of sources that use a carbon adsorption system must provide for the proper disposal or reuse of all VOC recovered.

II.F.4. Control of general solvent use

The owner or operator of operations that use solvents with uncontrolled actual VOC emissions greater than or equal to twenty-five (25) tons per year on a calendar year basis, and that are located in the 8-Hour Ozone Control Area, must reduce solvent use VOC emissions by 90%.

II.F.5. Monitoring requirements

- II.F.5.a. The owner or operator of operations that use solvents that utilize a closed-loop system for emission control must inspect the control system using audio, visual, olfactory (AVO) on a monthly basis for perceptible emissions. First attempt to repair must be made upon detection if feasible, but no later than three (3) calendar days from detection.
- II.F.5.b The owner or operator of operations that use solvents that utilize a control device must operate and maintain the control device consistent with the manufacturer's specifications.
- II.F.5.c. The owner or operator of operations that use solvents that are subject to the 90% control requirement in Section II.F.4. must:
 - II.F.5.c.(i) Complete a performance test once every three (3) years during representative operations to verify compliance with Section II.F.4. using one of the following methods, as applicable:
 - II.F.5.c.(i)(A) EPA Method 24 (40 CFR Part 60, Appendix A) (November 17, 2016) to determine VOC content.
 - II.F.5.c.(i)(B) EPA Method 18, 25, or 25A (40 CFR Part 60, Appendix A) (November 17, 2016) to determine control efficiency of the emission control equipment.
 - II.F.5.c.(ii) Conduct all performance tests in accordance with EPA test methods and a test protocol submitted to the Division for review at least thirty (30) days prior to testing and in accordance with AQCC Common Provisions Regulation Section II.C.

- II.F.5.c.(iii) Comply with control device and monitoring system manufacturers' specifications for operation and maintenance for equipment used to demonstrate compliance with Section II.F.4.

II.F.6. Recordkeeping

- II.F.6.a. Records of calendar year VOC emission estimates demonstrating whether the solvent operation meets or exceeds the applicability threshold in Section II.F.1.
- II.F.6.b. If applicable, records demonstrating that an exemption to Section II.F.2. applies.
- II.F.6.c. Monthly solvent losses based on beginning and ending inventories, solvent received, inventory adjustments, solvent destroyed in a control device, solvent recovered, and any volume of solvent normally retained in recovery equipment. Solvent losses must be totaled on a rolling 12-month basis.
- II.F.6.d. Monthly records such as safety data sheets or other analytical data from the solvent manufacturer showing the VOC type and VOC content, or the composite partial vapor pressure at 20 degrees Celsius, and total amount of VOC-containing solvent used in solvent operations.
- II.F.6.e. Records of negative pressure ranges, and other records necessary to demonstrate compliance with Section II.F.3.
- II.F.6.f. Manufacturer guarantee of the control equipment's emission control efficiency to demonstrate compliance with Section II.F.4.
- II.F.6.g. If applicable, monthly records of operation and maintenance of control device and monitoring system according to manufacturer's specifications to demonstrate compliance with Sections II.F.4. and II.F.5.
- II.F.6.h. If applicable, Records of performance tests conducted to demonstrate compliance with Section II.F.5.
- II.F.6.i. If applicable, monthly records of AVO inspections including:
 - II.F.6.i.(i) The date, facility name, and facility AIRS ID or facility location if the facility does not have an AIRS ID for each inspection;
 - II.F.6.i.(ii) A list of the leaks requiring repair,
 - II.F.6.i.(iii) The date of first attempt to repair the leak and, if necessary, any additional attempt to repair;
 - II.F.6.i.(iv) The date the leak was repaired and type of repair method applied.
- II.F.6.j. Records must be maintained for two (2) years and made available for inspection by the Division upon request.

III. Use of Cutback Asphalt

III.A. Definitions

- III.A.1. "Asphalt or Asphalt Cement" The dark-brown to black cementitious material (solid, semi-solid, or liquid in consistency) of which the main constituents are bitumen's which occur naturally or as a residue of petroleum refining.
- III.A.2. "Asphalt Concrete" A waterproof and durable paving material composed of dried aggregate, which is evenly coated with hot asphalt cement.
- III.A.3. "Cutback Asphalt or Cutback Asphalt Cement" Any asphalt which has been liquefied by blending with a VOC, such as a petroleum solvent diluents or, in the case of some slow cure asphalts (Road Oils), which has been produced directly from the distillation of petroleum.
- III.A.4. "Emulsified Asphalt" Asphalt emulsions produced by combining asphalt and water with emulsifying agent. Emulsified Asphalt or any other coating or sealant, including but not limited to those produced from petroleum or coal, which contain more than five (5) percent of oil distillate as determined by ASTM Method D-244 is included in this definition.
- III.A.5. "Penetrating Prime Coat" An application of low-viscosity liquid asphalt to an absorbent surface in order to prepare it for overlaying with a layer or layers of asphalt cement or asphalt emulsion and mineral aggregate paving materials.

III.B. Limitations

III.B.1. Applicability

The provisions of this Section III. apply to the use and storage of cutback asphalt for the paving and maintenance of all public roadways (including alleys), private roadways, parking lots, and driveways only within ozone nonattainment areas.

III.B.2. Storage

Stockpiles of aggregate mixed with cutback asphalt are permitted October 1 through February 28 (29). Such storage is not permitted March 1 through September 30 except where it can be demonstrated to the Division that such storage is necessary.

III.B.3. Use

Cutback asphalt may be used for any paving purpose October 1 through February 28 (29). No person shall use cutback asphalt or any coating included in the definition of cutback asphalt in Section III.A.3. March 1 through September 30 except as provided:

- III.B.3.a. If used solely as a penetrating prime coat, or
- III.B.3.b. If the user can demonstrate to the Division that under the conditions of its intended use, there will be no emissions of volatile organic compounds to the ambient air.

III.C. Recordkeeping

During the months of March through September, the person responsible for the use or storage of any cutback asphalt as permitted in Sections III.B.3.a., III.B.3.b., and Section III.B.2. shall keep records of same, including type and amount of solvent(s) used.

IV. Graphic Arts and Printing

IV.A. Packaging Rotogravure, Publication Rotogravure, and Flexographic Printing

IV.A.1. Definitions

For the purpose of this section, the following definitions apply:

- IV.A.1.a. "Flexographic Printing" means the application of words, designs, and pictures to a substrate by means of a roll printing technique in which the pattern to be applied is raised above the printing roll and the image carrier is made of rubber or other elastomeric materials.
- IV.A.1.b. "Packaging Rotogravure Printing" means rotogravure printing upon paper, paperboard, metal foil, plastic film, and other substrates, which are, in subsequent operations, formed into packaging products and labels for articles to be sold.
- IV.A.1.c. "Publication Rotogravure Printing" means rotogravure printing upon paper, which is subsequently formed into books, magazines, catalogues, brochures, directories, newspaper supplements, and other types of printed materials.
- IV.A.1.d. "Roll Printing" means the application of words, designs, and pictures to a substrate usually by means of a series of hard rubber or steel rolls each with only partial coverage.
- IV.A.1.e. "Rotogravure Printing" means the application of words, designs, and pictures to a substrate by means of a roll printing technique, which involves an intaglio or recessed image areas in the form of cells.

IV.A.2. Applicability

- IV.A.2.a. This section applies to all packaging rotogravure, publication rotogravure, and flexographic printing facilities whose potential emissions of volatile organic compounds before control (determined at design capacity and 8760 hrs/year, or at maximum production, and accounting for any capacity or production limitations in a federally-enforceable permit) are equal to or more than 90,000 Kg per year (100 tons/year). Potential emissions are to be estimated by extrapolating historical records of actual consumption of solvent and ink. (e.g., the historical use of 20 gallons of ink for 4,000 annual hours would be extrapolated to 43.8 gallons for 8760 hours.) The before-control volatile organic compound emissions calculations shall be the summation of all volatile organic compounds in the inks and solvents (including cleaning liquids) used.

IV.A.3. Provisions for Specific Processes

- IV.A.3.a. No owner or operator of a facility subject to this section and employing VOC-containing ink shall operate, cause, allow, or permit the operation of the facility unless:
- IV.A.3.a.(i) The volatile fraction of ink, as it is applied to the substrate, contains 25.0 percent or less (by volume) of VOC and 75.0 percent or more (by volume) of water; or
 - IV.A.3.a.(ii) The ink (minus water) as it is applied to the substrate, contains 60.0 percent or more (by volume) non-volatile material; or
 - IV.A.3.a.(iii) The owner or operator installs and operates a control device and capture system in accordance with Sections IV.A.3.b. and IV.A.3.c.; or
 - IV.A.3.a.(iv) A combination of solvent-borne inks and low solvent inks that achieve a 70% (volume) overall reduction of solvent usage (compared to an all solvent borne ink usage) is used; or
 - IV.A.3.a.(v) Flexographic and packaging rotogravure printing facilities limit emissions to 0.5 pounds of VOC per pound of solids in the ink. The limit includes all solvent added to the ink: solvent in the purchased ink, solvent added to cut the ink to achieve desired press viscosity, and solvent added to ink on the press to maintain viscosity during the press run. (Publication rotogravure facilities shall not use this option); or
 - IV.A.3.a.(vi) Crossline averaging is used. The requirements of Section I.A.5.d. apply.
- IV.A.3.b. A capture system shall be used in conjunction with the emission control system in Section IV.A.3.a. The design and operation of a capture system shall be consistent with good engineering practice, and in conjunction with control equipment shall be required to provide for an overall reduction in volatile organic compound emissions of at least:
- IV.A.3.b.(i) 75.0 percent where a publication rotogravure process is employed;
 - IV.A.3.b.(ii) 65.0 percent where a packaging rotogravure process is employed; or
 - IV.A.3.b.(iii) 60.0 percent where a flexographic printing process is employed.
- IV.A.3.c. The design, operation, and efficiency of any capture system used in conjunction with any emission control system shall be certified in writing by the source owner or operator and approved by the Division. Testing of any capture system may be required by the Division on a case-by-case basis, in cases where a total enclosure is not used or when material balance results are questionable. Testing of capture system efficiency shall meet the requirements of Section I.A.5.e.

- IV.A.3.d. The overall reduction in VOC emissions specified in Section IV.A.3.b. shall be calculated by material balance methods approved by the Division, or by determination of capture and control device efficiencies. The overall VOC emission reduction rate equals the (percent capture efficiency X percent control device efficiency)/100.

IV.A.4. Testing and Monitoring

The owner or operator of a source subject to the requirements of this section is also subject to the requirements of Part C, Sections I.A.3., I.A.7, I.A.9., and I.A.10. In Part C, Section I.A.3., EPA reference method 24A shall be the test method used for publication rotogravure inks, while EPA Reference method 24 data is acceptable for all other inks. Test methods as set forth in Appendix A, Part 60, Chapter I, Title 40, of the Code of Federal Regulations (CFR), in effect July 1, 1993.

- IV.A.5. The owner or operator of a source subject to the requirements of this section is also subject to the requirements of Section I.A.8. "A Guideline for Graphic Arts Calculations" shall be used for compliance determination.

IV.B. Lithographic and Letterpress Printing

IV.B.1. General Provisions

IV.B.1.a. Definitions

- IV.B.1.a.(i) "Alcohol" means any of the hydroxyl-containing organic compounds with a molecular weight equal to or less than 74.12, which includes methanol, ethanol, propanol, and butanol.
- IV.B.1.a.(ii) "Alcohol substitute" means nonalcohol additives that contain VOCs and are used in the fountain solution to reduce the surface tension of water or prevent ink piling.
- IV.B.1.a.(iii) "Cleaning material" means a VOC-containing material used to remove ink and debris from the printing press area, operating surfaces of the printing press and, printing press parts. Blanket wash is a type of cleaning material.
- IV.B.1.a.(iv) "Composite partial vapor pressure" means the sum of the partial pressures of the compounds defined as VOCs. Composite partial vapor pressure is calculated as follows:

$$PP_c = \frac{\sum_{i=1}^n \frac{(W_i)(VP_i)/MW_i}{\frac{W_w}{MW_w} + \sum_{c=1}^n \frac{W_c}{MW_c} + \sum_{i=1}^n \frac{W_i}{MW_i}}}$$

Where:

- W_i = Weight of the "i"th VOC compound, in grams
W_w = Weight of water, in grams
W_e = Weight of exempt compound, in grams
MW_i = Molecular weight of the "i"th VOC compound, in g/g-mole
MW_w = Molecular weight of water, in g/g-mole
MW_c = Molecular weight of exempt compound, in g/g-mole
PP_c = VOC composite partial vapor pressure at 20°C (68°F), in mm Hg
VP_i = Vapor pressure of the "i"th VOC compound at 20°C(68°F), in mm Hg

- IV.B.1.a.(v) "Fountain solution" means a mixture of water, nonvolatile printing chemicals, and a liquid additive that reduces the surface tension of the water so that it spreads easily across the printing plate surface. The fountain solution wets the non-image areas so that the ink is maintained within the image areas.
- IV.B.1.a.(vi) "Heatset" means any lithographic or letterpress printing operation where printing inks are set by the evaporation of the ink oils in a heatset dryer.
- IV.B.1.a.(vii) "Heatset dryer" means a hot air dryer used in heatset lithography to heat the printed substrate and to promote the evaporation of ink oils.
- IV.B.1.a.(viii) "Lithographic printing" means a planographic printing process where the image and non-image areas are chemically differentiated (the image area is oil receptive and the non-image area is water receptive). This printing process differs from other conventional printing methods, where the image is a raised or recessed surface.
- IV.B.1.a.(ix) "Letterpress printing" means a printing process in which the image area is raised relative to the non-image area and the paste ink is transferred to the substrate directly from the image surface.
- IV.B.1.a.(x) "Non-heatset" means any printing operation where the printing inks are set without the use of heat. For the purpose of Section IV.B., ultraviolet-cured and electron beam-cured inks are considered non-heatset.
- IV.B.1.a.(xi) "Offset lithographic printing" means a printing process that transfers the ink film from the lithographic plate to an intermediary surface (blanket), which in turn transfers the ink film to the substrate.
- IV.B.1.a.(xii) "Press" means a printing production assembly composed of one or more print units used to produce a printed substrate including any associated coating, spray powder application, heatset web dryer, ultraviolet or electron beam curing units, or infrared heating units.
- IV.B.1.a.(xiii) "Sheet-fed printing" means a printing process where individual sheets of paper or substrate are fed into the printing press.
- IV.B.1.a.(xiv) "Web printing" means a printing process where continuous rolls of substrate material are fed to the press and rewound or cut to size after printing.

IV.B.1.b. Applicability

- IV.B.1.b.(i) The provisions of this Section IV.B. apply to fountain solutions, cleaning materials, inks (which include varnishes) and coatings used in lithographic and letterpress printing presses. These materials are not subject to the requirements of Sections I. and II.
- IV.B.1.b.(ii) The work practice requirements in Section IV.B.1.c. apply to all lithographic and letterpress printing operations.
- IV.B.1.b.(iii) The VOC content limit for inks in Section IV.B.1.d. applies to lithographic and letterpress printing operations where total combined uncontrolled actual VOC emissions from each printing operation, including related cleaning materials and fountain solutions, are equal to or greater than three (3) tons per calendar year.
- IV.B.1.b.(iv) The cleaning material requirements in Section IV.B.2. apply to letterpress printing operations where total combined uncontrolled actual VOC emissions from each printing operation, including related cleaning materials and fountain solutions, are equal to or greater than three (3) tons per calendar year.
- IV.B.1.b.(v) The cleaning material and fountain solution requirements in Sections IV.B.2. and IV.B.3. apply to offset lithographic printing operations where total combined uncontrolled actual VOC emissions from each printing operation, including related cleaning materials and fountain solutions, are equal to or greater than three (3) tons per calendar year.
- IV.B.1.b.(vi) The control requirements in Section IV.B.4. apply to each heatset web offset lithographic and heatset web letterpress printing press with the potential to emit from the dryer, prior to controls, at least 25 tons per calendar year of VOC (petroleum ink oil) from heatset inks.

IV.B.1.c. Work Practice Requirements

Lithographic and letterpress printing operations must implement the following work practices at all times to reduce VOC emissions from fugitive sources:

- IV.B.1.c.(i) Cover open containers and keep cleaning materials in closed containers when not in use;
- IV.B.1.c.(ii) Properly dispose of used cleaning materials, fountain solutions, and used shop towels; and
- IV.B.1.c.(iii) Implement good air pollution control practices that minimize emissions, including, but not limited to, using only volumes necessary for cleaning and maintain cleaning equipment to repair cleaning materials leaks.

IV.B.1.d. VOC Content Limit for Inks

- IV.B.1.d.(i) Lithographic and letterpress printing operations, excluding heatset web offset and heatset web letterpress printing operations, must use low-VOC inks, which average less than 30% (by weight) VOC on a monthly basis.
- IV.B.1.d.(ii) Heatset web offset lithographic and heatset web letterpress printing operations must use low-VOC inks, which average less than 40% (by weight) VOC on a monthly basis.

IV.B.2. Offset lithographic printing and letterpress printing operations must comply with the following cleaning materials requirements;

IV.B.2.a. All cleaning materials must contain less than 70% (by weight) VOC or have a VOC composite vapor pressure less than 10 mmHg at 20°C.

IV.B.2.b. Exemptions

The following materials and operations are exempt from the cleaning material requirements in Section IV.B.2.a.:

- IV.B.2.b.(i) Cleaners used on electronic components of a press.
- IV.B.2.b.(ii) Pre-press cleaning operations.
- IV.B.2.b.(iii) Post-press cleaning operations.
- IV.B.2.b.(iv) Floor cleaning supplies (other than those used to clean dried ink).
- IV.B.2.b.(v) Cleaning performed in parts washers or cold cleaners that are subject to Section II.

IV.B.2.c. Use of non-compliant cleaning materials

Cleaning materials not meeting the limits in Section IV.B.2.a. are limited to less than or equal to 110 gallons per calendar year.

IV.B.3. Offset lithographic printing operations must comply with the following fountain solution requirements:

IV.B.3.a. Heatset web offset lithographic printing operations must:

- IV.B.3.a.(i) Use a fountain solution containing 1.6% alcohol (by weight) or less as applied;
- IV.B.3.a.(ii) Use a fountain solution containing 3% alcohol (by weight) or less as applied if the fountain solution is refrigerated to below 60°F (15.5°C); or
- IV.B.3.a.(iii) Use a fountain solution containing 5% alcohol substitute (by weight) or less as applied and no alcohol.

IV.B.3.b. Sheet-fed printing operations must

- IV.B.3.b.(i) Use a fountain solution containing 5% alcohol (by weight) or less as applied;
- IV.B.3.b.(ii) Use a fountain solution containing 8.5% alcohol (by weight) or less as applied if the fountain solution is refrigerated to below 60°F (15.5°C); or
- IV.B.3.b.(iii) Use a fountain solution containing 5% alcohol substitute (by weight) or less as applied and no alcohol.
- IV.B.3.b.(iv) The following are exempt from the fountain solution requirements in Section IV.B.3.b.:
 - IV.B.3.b.(iv)(A) Fountain solution use associated with a sheet-fed printing press with maximum sheet size 11x17 inches or smaller.
 - IV.B.3.b.(iv)(B) Fountain solution use associated with a sheet-fed printing press having a total fountain solution reservoir less than one (1) gallon.
- IV.B.3.c. Non-heatset web printing must use a fountain solution containing 5% alcohol substitute (by weight) or less and no alcohol.
- IV.B.4. Heatset web offset lithographic and heatset web letterpress printing operations must comply with the following control requirements:
 - IV.B.4.a. Heatset web offset lithographic and heatset web letterpress printing operations must reduce VOC emissions from heatset dryers with an emission control system having a control efficiency of 90% or greater.
 - IV.B.4.b. If the control device was first installed on or after January 1, 2017, heatset web offset lithographic and heatset web letterpress printing operations must reduce VOC emissions from heatset dryers with an emission control system having a control efficiency of 95% or greater.
 - IV.B.4.c. Where inlet VOC concentration is low and a 90 or 95% control efficiency is not achievable due to low inlet concentrations or measurable due to equipment configuration, heatset web offset lithographic and heatset web letterpress printing operations may reduce the control device outlet concentration to 20 ppmv (as hexane on a dry basis).
 - IV.B.4.d. The following are exempt from the control requirements in Section IV.B.4.:
 - IV.B.4.d.(i) Heatset presses used for book printing.
 - IV.B.4.d.(ii) Heatset presses with maximum web width of 22 inches or less.
 - IV.B.4.d.(iii) Waterborne or radiation (ultra-violet or electron beam) cured materials that are not heatset.
- IV.B.5. Monitoring, Recordkeeping and Reporting

- IV.B.5.a. The owner or operator of a heatset web offset lithographic or heatset web letterpress printing operation required to demonstrate compliance with Section IV.B.4. must install, calibrate, maintain, and operate a temperature monitoring device, according to the manufacturer's specifications.
- IV.B.5.b. The owner or operator of a lithographic and letterpress printing operations subject to Sections IV.B.1.d. and IV.B.2. through IV.B.4. must keep the following records for two (2) years and make them available for inspection by the Division upon request:
 - IV.B.5.b.(i) If applicable, records demonstrating that a listed exemption to this Section IV.B. applies.
 - IV.B.5.b.(ii) If applicable, monthly records of the type, alcohol content or alcohol substitute content, and total volume of fountain solution used in printing operations.
 - IV.B.5.b.(iii) If applicable, monthly records of the type, VOC content or composite vapor pressure, and total volume of the cleaning materials used in printing operations.
 - IV.B.5.b.(iv) If applicable, monthly records of the type, VOC content, and total volume of inks (including varnishes) and coatings used in printing operations.
 - IV.B.5.b.(v) If applicable, monthly records demonstrating compliance with the control requirements in Section IV.B.4.
 - IV.B.5.b.(vi) Records of calendar year VOC emission estimates demonstrating whether the printing operation meets or exceed the applicability thresholds in Section IV.B.1.b.
- IV.B.5.c. Compliance with control requirements must be demonstrated using the following methods as applicable:
 - IV.B.5.c.(i) Safety data sheets or other analytical data from the ink, cleaning material, or fountain solution manufacturer to demonstrate compliance with VOC content limit for inks in Section IV.B.1.d., the cleaning material requirements in Section IV.B.2., and the fountain solution requirements in Section IV.B.3.;
 - IV.B.5.c.(ii) A manufacturer guarantee of the control equipment's emission control efficiency and operation and maintenance of control equipment according to manufacturer's specifications to demonstrate compliance with the control equipment requirements in Section IV.B.4.; or
 - IV.B.5.c.(iii) A performance test conducted during representative conditions using one of the following methods as applicable:
 - IV.B.5.c.(iii)(A) EPA Method 24 (40 CFR Part 60, Appendix A) (November 17, 2016) to determine VOC content for inks, fountain solutions and cleaning materials; or

IV.B.5.c.(iii)(B) EPA Method 18, 25, or 25A (40 CFR Part 60, Appendix A) (November 17, 2016) to determine control efficiency or outlet concentration of the emission control equipment.

V. Pharmaceutical Synthesis

V.A. General Provisions

V.A.1. Applicability

This section applies to all sources of volatile organic compounds associated with pharmaceutical manufacturing activities, including, but not limited to, reactors, distillation units, dryers, storage of VOCs, extraction equipment, filters, crystallizers, and centrifuges.

V.A.2. Exemptions

Extraction of organic substances from animal or vegetable material; fermentation and culturing; formulation and packaging of pharmaceutical or medicinal products.

V.A.3. Definitions

For the purpose of this section, the following definitions apply:

V.A.3.a. "Control System" means any number of control devices, including condensers, which are designed and operated to reduce the quantity of VOC emitted to the atmosphere.

V.A.3.b. "Pharmaceutical" means a medicine or drug which appears in the United States Pharmacopoeia National Formulary, or which is so designated by the National Drug Code of the United States FDA Bureau of Drugs.

V.A.3.c. "Production Equipment Exhaust System" means a device for collecting and directing out of the work area VOC fugitive emissions from reactor openings, centrifuge openings, and other vessel openings for the purpose of protecting workers from excessive VOC exposure.

V.A.3.d. "Reactor" means a vat or vessel, which may be jacketed to permit temperature control, designed to contain chemical reactions.

V.A.3.e. "Separation Operation" means a process that separates a mixture of compounds and solvents into two or more components. Specific mechanisms include, but are not limited to, extraction, centrifugation, filtration, distillation, and crystallization.

V.A.3.f. "Synthesized Pharmaceutical Manufacturing" means manufacture of pharmaceutical products by chemical synthesis. It includes the manufacture of chemical intermediates (of sufficient purity) which are typically used by the pharmaceutical industry as precursors to finished mixtures of chemicals. (Thus, it excludes those chemical processes which are not directed at creating finished pharmaceutical or chemical intermediates to finished pharmaceuticals.)

V.B. Provisions for Specific Processes

- V.B.1. The owner or operator of a facility subject to this section shall control the volatile organic compound emissions from each vent which has the potential to emit 6.80 kg/day (15 lb./day) or more of VOC from reactors, distillation operations, crystallizers, centrifuge and vacuum dryers. Surface condensers or equivalent controls shall be used, provided that, if surface condensers are used, the condenser outlet gas temperature shall not exceed the following values:

VOCs True Vapor Pressure* at 20° in torr (and psia) from (minimum) up to ** (maximum)	Maximum temperature of Gas Stream immediately exiting the condenser
0-26(0-0.5)	35°C (95°F)
26-52(0.5-1.0)	25°C(77°F)
52-78(1.0-1.5)	10°C(50°F)
78-150(1.5-2.9)	0°C(32°F)
150-300(2.9-5.8)	-15°C(5°F)
Greater than 300(Greater than 5.8)	-25°C(-13°F)

*The calculation methods for gases containing more than one condensable component are complex. As a simplification, the temperature necessary for control by condensation can be roughly approximated by the weighted average of the temperatures necessary for condensation of each VOC considered separately but at concentrations equal to the total organic concentration.

**But not including the maximum value of the range.

- V.B.2. Division approval shall be required for control equipment used to control VOCs of 570 torr (11 psia) and above.
- V.B.3. The owner or operator of a facility subject to this section shall reduce the VOC emissions from each air dryer and production equipment exhaust system:
- V.B.3.a. By at least 90 percent if emissions are 150 kg/day (330 lbs/day) or more of VOC,
or,
- V.B.3.b. To 15.0 kg/day (33 lb/day) or less if emissions are less than 150 kg/day (330 lb/day) of VOC.
- V.B.4. The owner or operator of a facility subject to this section shall:
- V.B.4.a. Provide a vapor balance system or equivalent control that is at least 90.0 percent effective in reducing emissions from truck or railcar deliveries to storage tanks with capacities greater than 7,570 liters (2,000 gallons) that store VOC with true vapor pressure greater than 210 torr (4.1 psia) at 20°C; and,
- V.B.4.b. Install pressure/vacuum conservation vents set at plus or minus 0.2 kPa on all storage tanks that store VOC with true vapor pressures greater than 10.0 kPa (1.5 psi) at 20°C.

- V.B.5. The owner or operator of a facility subject to this section shall enclose all centrifuges, rotary vacuum filters, and other filters having an exposed liquid surface, where the liquid contains VOC and exerts a total VOC true vapor pressure of 26 torr (0.5 psia) or more at 20°C.
- V.B.6. The owner or operator of a synthesized pharmaceutical facility subject to this section shall install covers on all in-process tanks containing a volatile organic compound at any time. These covers shall remain closed unless sampling, maintenance, short-duration production procedures or inspection procedures require access.
- V.B.7. The owner or operator of a facility subject to this section shall repair all leaks from which a liquid, containing VOC, can be observed running or dripping. The repair shall be completed the first time the equipment is off-line for a period of time long enough to complete the repair, except that no leak shall go unrepaired for more than 14 days after initial detection unless the Division issues written approval.
- V.B.8. Each surface condenser shall have at least one temperature indicator with its sensor located in the outlet gas stream.

V.C. Testing and Monitoring

- V.C.1. Sources subject to the requirements of this section are also subject to the requirements of Sections I.A.3., I.A.7., I.A.8., and I.A.9.

Appendix D Minimum Cooling Capacities for Refrigerated Freeboard Chillers on Vapor Degreasers

The specifications in this Appendix apply only to vapor degreasers that have both condenser coils and refrigerated freeboard chillers. (The coolant in the condenser coils is normally water.) The amount of refrigeration capacity is expressed in Calories/Hour per meter of perimeter. This perimeter is measured at the air/vapor interface.

For refrigerated chillers operated below 0°C., the following requirements apply:

DEGREASER WIDTH	*CALORIES/HR METER OF PERIMETER	BTU/HR FOOT OF PERIMETER
Less than 1.1 meters (3.5 ft.)	165	200
1.1 - 1.8 meters (3.5 - 6.0 ft.)	250	300
1.8 - 2.4 meters (6.0 - 8.0 ft.)	335	400
2.4 - 3.0 meters (8.0 - 10.0 ft.)	145	500
Greater than 3.0 meters (10 ft.)	500	600

* Kilocalories (1 Kilocalorie = 4184.0 joules)

For refrigerated chillers operating above 0°C., there shall be at least 415 Calories/Hr. - meter of perimeter (500 BTU/Hr-ft.), regardless of size.

Definition: "Air/Vapor Interface" - means the surface defined by the top of the solvent vapor layer within the confines of a vapor degreaser.

Appendix E Emission Limit Conversion Procedure

The following procedure shall be used to convert emission limits expressed as lb VOC/gallon coating less water and exempt solvents to limits expressed as lb VOC/gallon solids. This example uses the emission limit of 3.7 lb VOC/gallon coating.

Assume VOC density of the 'Presumptive' RACT coating is 7.36 pounds per gallon because this same value was used to determine the "Presumptive" recommended RACT emission limits from volume solids data.

$(3.7) \text{ LB VOC} / \text{GAL COATING LESS WATER} \times 100 / 7.36 \text{ LB VOC} = (50) \text{ VOL\% VOC}$
$100 - (50) \text{ VOL\% VOC} = (50) \text{ VOL\% SOLIDS}$
$(3.7) \text{ LB VOC} / \text{GAL COATING LESS H}_2\text{O} \times 100 \text{ GAL COATING} / (50) \text{ GAL SOLIDS} = (7.4) \text{ LB VOC} / \text{GAL SOLIDS}$

See "A Guideline for Surface Coating Calculations" EPA - 340/1-86-016 for additional examples.

The following table lists equivalent mass VOC/volume solids emission limits for various coating operations.

Equivalency Data for Surface Coating Processes (VOC Density = 7.36 lb/gal)

Industrial Finishing Categories	Lb VOC per Gallon Coating less water	Lb VOC per Gallon of Solids	Kg VOC per Liter of Solids
<i>Can Industry</i>			
Sheet Basecoat (Exterior and Interior) and over-varnish; two-piece can exterior (base-coat and over-varnish)	2.8	4.5	0.55
Two- and three-piece can interior body spray, two-piece can exterior end spray or roll coat	4.2	9.8	1.19
Three-piece can side-seam spray	5.5	21.7	2.61
End sealing compound	3.7	7.4	0.88
Any additional coats	4.2	9.8	1.19
<i>Coil Coating</i>			
Any coat	2.6	4.0	0.48

<i>Fabric Coating</i>			
Fabric coating line	2.9	4.8	0.58
Vinyl coating line	3.8	7.9	0.93
<i>Paper Coating</i>			
Coating line	2.9	4.8	0.58
<i>Automotive and Light-Duty Truck Assembly Plant</i>			
Primer (electrodeposition) application, flashoff area and oven	1.9	2.6	0.31
Topcoat application, flashoff area and oven	2.8	4.5	0.55
Final repair application, flashoff area and oven	4.8	13.8	1.67
<i>Metal Furniture</i>			
Coating line	3.0	5.1	0.61
<i>Magnet Wire</i>			
Wire coating operation	1.7	2.2	0.26
<i>Large Appliances</i>			
Prime, single, or topcoat application area, flashoff area and oven	2.8	4.5	0.55
<i>Miscellaneous Metal Parts and Products</i>			
Air-dried items	3.5	6.7	0.80
Clear-coated items	4.3	10.3	1.25
Extreme performance coatings	3.5	6.7	0.80
Other coatings and systems	3.0	5.1	0.61
<i>Plastic Film Coating</i>			
Plastic film coating line	2.9	4.8	0.58

PART D Oil and Natural Gas Operations

I. Volatile Organic Compound Emissions from Oil and Gas Operations

I.A. Applicability

I.A.1. Except as provided in Section I.A.2., this section applies to oil and gas operations that collect, store, or handle hydrocarbon liquids or produced water in the 8-hour Ozone Control Area (State Only: or any ozone nonattainment or attainment/maintenance area) and that are located at or upstream of a natural gas plant.

I.A.2. Oil refineries are not subject to Section I.

I.B. Definitions specific to Section I.

I.B.1. “Affected Operations” means oil and gas exploration and production operations, natural gas compressor stations and natural gas drip stations, to which Section I. applies.

I.B.2. “Air Pollution Control Equipment”, as used in Section I., means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment, pollution prevention devices, and processes that comply with the requirements of Section I.D.4. that are approved by the Division.

I.B.3. “Approved Instrument Monitoring Method” means an infra-red camera, EPA Method 21, or other instrument based monitoring method or program approved in accordance with Section I.L.8. If an owner or operator elects to use Division approved continuous emission monitoring, the Division may approve a streamlined inspection, recordkeeping, and reporting program for such operations.

I.B.4. “Atmospheric Storage Tanks or Atmospheric Condensate Storage Tanks” means a type of condensate storage tank that vents, or is designed to vent, to the atmosphere.

I.B.5. “Auto-Igniter” means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust volatile organic compound emissions.

I.B.6. “Calendar Week” means a week beginning with Sunday and ending with Saturday.

I.B.7. “Commencement of operation” means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).

I.B.8. “Condensate Storage Tank” means any tank or series of tanks that store condensate and are either manifolded together or are located at the same well pad.

I.B.9. “Centrifugal Compressor” means any machine used for raising the pressure of natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors.

I.B.10. “Component” means each pump seal, flange, pressure relief device (including thief hatches or other openings on a controlled storage tank), connector, and valve that

contains or contacts a process stream with hydrocarbons, except for components in process streams consisting of glycol, amine, produced water, or methanol.

- I.B.11. "Connector" means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors.
- I.B.12. "Custody Transfer" means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.
- I.B.13. "Downtime" means the period of time when a well is producing and the air pollution control equipment is not in operation.
- I.B.14. "Existing" means any atmospheric condensate storage tank that began operation before February 1, 2009, and has not since been modified.
- I.B.15. "Glycol Natural Gas Dehydrator" means any device in which a liquid glycol (including, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.
- I.B.16. "Hydrocarbon liquids" means any naturally occurring, unrefined petroleum liquid. Hydrocarbon liquids does not include produced water.
- I.B.17. "Infra-red Camera" means an optical gas imaging instrument designed for and capable of detecting hydrocarbons.
- I.B.18. "Modified or Modification" means any physical change or change in operation of a stationary source that results in an increase in actual uncontrolled volatile organic compound emissions from the previous calendar year that occurs on or after February 1, 2009. For atmospheric condensate storage tanks (and beginning March 1, 2020, for all storage tanks), a physical change or change in operation includes but is not limited to drilling wells and recompleting, refracturing or otherwise stimulating existing wells.
- I.B.19. "Natural Gas Compressor Station" means a facility, located downstream of well production facilities, which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure prior to the inlet of a natural gas processing plant.
- I.B.20. "Natural Gas-Driven Diaphragm Pump" means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.
- I.B.21. "Natural Gas Processing Plant" means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.
- I.B.22. "New" means any atmospheric condensate storage tank that began operation on or after February 1, 2009.

- I.B.23. "Produced Water" means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.
- I.B.24. "Reciprocating Compressor" means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of the piston rod.
- I.B.25. "Stabilized" when used to refer to stored hydrocarbon liquids, means that the hydrocarbon liquids have reached substantial equilibrium with the atmosphere and that any emissions that occur are those commonly referred to within the industry as "working and breathing losses".
- I.B.26. "Storage tank" means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage tanks may be located at a well production facility or other location.
- I.B.27. "Storage vessel" means a tank or other vessel that contains an accumulation of hydrocarbon liquids or produced water and is constructed primarily of nonearthed materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after commencement of operation for a period which exceeds 60 days is considered a storage vessel. Storage vessel does not include vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and are intended to be located at the site for less than 180 consecutive days; process vessels such as surge control vessels, bottom receivers, or knockout vessels; or pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.
- I.B.28. (State Only) "Surveillance System" means monitoring pilot flame presence or temperature in a combustion device either by visual observation or with an electronic device to record times and duration of periods where a pilot flame is not detected at least once per day.
- I.B.29. "System-Wide Control Strategy" means the collective emissions and emission reductions from all atmospheric condensate storage tanks under common ownership within the 8-hour Ozone Control Area for which uncontrolled actual volatile organic compound emissions are equal to or greater than two tons per year.
- I.B.30. "Well Production Facility" means all equipment at a single stationary source directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

I.C. General Provisions

I.C.1. General Requirements

- I.C.1.a. All air pollution control equipment used to demonstrate compliance with this Section I. must be operated and maintained consistent with manufacturer specifications and good engineering and maintenance practices. The owner or operator must keep manufacturer specifications on file. In addition, all such air pollution control equipment must be adequately designed and sized to achieve the control efficiency rates required by this Section I. and to handle reasonably foreseeable fluctuations in emissions of volatile organic compounds. Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.
- I.C.1.b. All hydrocarbon liquids and produced water collection, storage, processing, and handling operations, regardless of size, must be designed, operated, and maintained so as to minimize emission of volatile organic compounds to the atmosphere to the maximum extent practicable.
- I.C.1.c. All air pollution control equipment used to demonstrate compliance with Sections I.D., I.J., and I.K. must meet a control efficiency of at least 95%. Failure to properly install, operate, and maintain air pollution control equipment is a violation of this regulation.
- I.C.1.d. If a flare or other combustion device is used to control emissions of volatile organic compounds to comply with Sections I.D., I.J., and I.K. it must be enclosed, have no visible emissions, and be designed so that an observer can, by means of visual observation from the outside of the enclosed flare or combustion device, or by other convenient means, such as a continuous monitoring device, approved by the Division, determine whether it is operating properly.
- I.C.1.e. All combustion devices used to control emissions of volatile organic compounds to comply with Sections I.D., I.J., and I.K. must be equipped with and operate an auto-igniter as follows:
- I.C.1.e.(i) (State Only) For condensate storage tanks that are constructed or modified after May 1, 2009, and before January 1, 2017, and controlled by a combustion device, auto-igniters must be installed and operational, beginning the date of first production after any new tank installation or tank modification.
 - I.C.1.e.(ii) (State Only) For all existing condensate storage tanks controlled by a combustion device in order to comply with the emissions control requirements of Section I.D.1., auto-igniters must be installed and operational beginning May 1, 2009, for condensate storage tanks with actual uncontrolled emissions of greater than or equal to 50 tons per year, and beginning May 1, 2010, for all other existing condensate storage tanks controlled by a combustion device, or within 180 days from first having installed the combustion device, whichever date comes later.
 - I.C.1.e.(iii) All combustion devices installed on or after January 1, 2017, must be equipped with an operational auto-igniter upon installation of the combustion device.

- I.C.1.e.(iv) All combustion devices installed on or after January 1, 2018, and used to comply with Sections I.J. or I.K. must be equipped with an operational auto-igniter upon installation of the combustion device.
- I.C.1.f. (State Only) If a combustion device is used to control emissions of volatile organic compounds, surveillance systems must be employed and operational as follows:
- I.C.1.f.(i) (State Only) Beginning May 1, 2010, for all existing condensate storage tanks with uncontrolled actual emissions of 100 tons per year or more based on data from the previous twelve consecutive months.
- I.C.1.f.(ii) (State Only) For all new and modified condensate storage tanks controlled by a combustion device for the first 90 days surveillance systems must be employed and operational beginning 180 days from commencement of operation after the tank was newly installed, or after the well was newly drilled, re-completed, re-fractured or otherwise stimulated, if uncontrolled actual emissions projected for the first twelve months based on data from the first 90 days of operation from the condensate storage tank are 100 tons or more of uncontrolled VOCs.
- I.C.2. The emission estimates and emission reductions required by Section I.D. must be demonstrated using one of the following emission factors:
- I.C.2.a. In the 8-Hour Ozone Control Area
- I.C.2.a.(i) For atmospheric condensate storage tanks at oil and gas exploration and production operations, a default emission factor of 13.7 pounds of volatile organic compounds per barrel of condensate must be used unless a more specific emission factor has been established pursuant to Section I.C.2.a.(iii). The Division may require a more specific emission factor that complies with Section I.C.2.a.(iii).
- I.C.2.a.(ii) For atmospheric condensate storage tanks at natural gas compressor stations and natural gas drip stations a source may use a specific emissions factor that was used for reporting emissions from the source on APENs filed on or before February 28, 2003. The Division may, however, require the source to develop and use a more recent specific emission factor pursuant to Section I.C.2.a.(iii) if such a more recent emission factor would be more reliable or accurate.
- I.C.2.a.(iii) Except as otherwise provided in Section I.C.2.a.(i), a specific emission factor is one for which the Division has no objection, and which is based on collection and analysis of a representative sample of the hydrocarbon liquids or produced water pursuant to a test method approved by the Division.

- I.C.2.a.(iv) For storage tanks storing produced water or hydrocarbon liquids other than condensate, the most recent Division-approved default emission factors must be used unless a more specific emission factor has been established pursuant to Section I.C.2.a.(iii).
- I.C.2.a.(v) If the Division has reason to believe that a specific emission factor is no longer representative, or if it deems it otherwise necessary, the Division may require the use of an alternative emission factor that complies with Section I.C.2.a.(iii).
- I.C.2.b. (State Only) For any other Ozone Nonattainment Area or Attainment/Maintenance Areas
 - I.C.2.b.(i) (State Only) For storage tanks at oil and gas exploration and production operations, the source must use a default basin-specific uncontrolled volatile organic compound emission factor established by the Division unless a site-specific emission factor has been established pursuant to Section I.C.2.b.(iii). If the Division has established no default emission factor, if the Division has reason to believe that the default emission factor is no longer representative, or if it deems it otherwise necessary, the Division may require use of an alternative emission factor that complies with Section I.C.2.b.(iii).
 - I.C.2.b.(ii) (State Only) For storage tanks at natural gas compressor stations and natural gas drip stations, the source must use a site-specific volatile organic compound emission factor established pursuant to Section I.C.2.b.(iii). If the Division has reason to believe that the site-specific emission factor is no longer representative, or if it deems it otherwise necessary, the Division may require use of an alternative emission factor that complies with Section I.C.2.b.(iii).
 - I.C.2.b.(iii) (State Only) Establishment of or Updating Approved Emission Factors
 - I.C.2.b.(iii)(A) (State Only) The Division may require the source to develop and/or use a more recent default basin-specific or site-specific volatile organic compound emission factor pursuant to Section I.C.2.b., if such emission factor would be more reliable or accurate.
 - I.C.2.b.(iii)(B) (State Only) For storage tanks at oil and gas exploration and production operations, the source may use a site-specific volatile organic compound emission factor for which the Division has no objection, and which is based on collection and analysis of a representative sample of hydrocarbon liquids or produced water pursuant to a test method approved by the Division.

- I.C.2.b.(iii)(C) (State Only) For storage tanks at natural gas compressor stations and natural gas drip stations, a source may use a volatile organic compound emissions factor that was used for reporting emissions from the source on APENs filed on or before February 28, 2003, or an alternative site-specific volatile organic compound emission factor established pursuant to Section I.C.2.b.
- I.C.2.b.(iii)(D) (State Only) A default basin-specific volatile organic compound emissions factor must be one for which the Division has no objection, and which is based on collection and analysis of a representative sample of hydrocarbon liquids or produced water or an alternative method, pursuant to a test method approved by the Division, except as otherwise provided in I.C.2.b.(i).
- I.C.2.b.(iii)(E) (State Only) A site-specific volatile organic compound emissions factor must be one for which the Division has no objection, and which is based on collection and analysis of a representative sample of hydrocarbon liquids or produced water pursuant to a test method approved by the Division.

I.D. Storage Tank Emission Controls

I.D.1. System-Wide Control Strategy for Condensate Storage Tanks

- I.D.1.a. Beginning May 1, 2011, through April 30, 2020, owners and operators of all atmospheric condensate storage tanks that emit greater than or equal to two tons per year of actual uncontrolled volatile organic compounds must employ air pollution control equipment to reduce emissions of volatile organic compounds from atmospheric condensate storage tanks by 90% from uncontrolled actual emissions on a calendar weekly basis May 1 through September 30 and 70% from uncontrolled actual emissions on a calendar monthly basis during October 1 through April 30.

Emission reductions are not required for each and every unit, but instead shall be based on overall reductions in uncontrolled actual emissions from all the atmospheric condensate storage tanks associated with the affected operations for which the owner or operator filed, or was required to file, an APEN pursuant to Regulation Number 3, Part A, due to either having exceeded reporting thresholds or retrofitting with air pollution control equipment in order to comply with the system-wide control strategy.

- I.D.1.b. The system-wide control strategy does not apply to natural gas-processing plants subject to Section I.G. or qualifying natural gas compressor stations subject to Section I.I.
- I.D.1.c. The system-wide control strategy does not apply to any owner or operator where the APENs for all of the atmospheric condensate storage tanks associated with the affected operations owned or operated by such person in calendar year 2019 or January 1, 2020, through April 30, 2020, reflect a total of less than 30 tons-per-year of actual uncontrolled emissions of VOCs in the 8-Hour Ozone Control Area.

I.D.2. New and Modified Condensate Tanks

I.D.2.a. Beginning February 1, 2009, through March 1, 2020, owners or operators of any new or modified atmospheric condensate storage tank at exploration and production sites shall collect and control emissions by routing emissions to and operating air pollution control equipment pursuant to Section I.D. The air pollution control equipment shall have a control efficiency of at least 95%, and shall control volatile organic compounds during the first 90 calendar days after commencement of operation of the storage tank, or after the well was re-completed, re-fractured or otherwise stimulated. The air pollution control equipment and associated monitoring equipment required pursuant to Section I.C.1. may be removed after the first 90 calendar days as long as the source can demonstrate compliance with the applicable system-wide standard.

I.D.3. Storage Tank Control Strategy

I.D.3.a. Applicability

I.D.3.a.(i) Owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than four (4) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves a VOC control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for VOC, except where the combustion device has been authorized by permit prior to March 1, 2020.

I.D.3.a.(ii) (State Only) Owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than two (2) tons per year based on a rolling twelve-month total and not subject to Section I.D.3.a.(i) must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves a VOC control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for VOC, except where the combustion device has been authorized by permit prior to March 1, 2020.

I.D.3.b. Compliance Deadlines

I.D.3.b.(i) A storage tank subject to Section I.D.3.a.(i) and constructed on or after March 1, 2020, must be in compliance by commencement of operation of that storage tank.

I.D.3.b.(ii) (State Only) A storage tank subject to Section I.D.3.a.(ii) and constructed on or after March 1, 2020, must be in compliance by commencement of operation of that storage tank.

I.D.3.b.(iii) A storage tank subject to Section I.D.3.a.(i) and constructed before March 1, 2020, must be in compliance by May 1, 2020, or by commencement of operation of the storage tank, whichever comes later.

- I.D.3.b.(iv) (State Only) A storage tank subject to Section I.D.3.a.(ii) and constructed before March 1, 2020, must be in compliance by May 1, 2020, or by commencement of operation of the storage tank, whichever comes later.
 - I.D.3.b.(v) A storage tank subject to Section I.D.3.a.(i) and not otherwise subject to Sections I.D.3.b.(i). or I.D.3.b.(iii) that increases uncontrolled actual emissions to four (4) tons per year VOC or more on a rolling twelve-month basis after March 1, 2020, must be in compliance within sixty (60) days of the first day of the month after which the storage tank VOC emissions exceeded four (4) tons per year on a rolling twelve-month basis.
 - I.D.3.b.(vi) (State Only) A storage tank subject to Section I.D.3.a.(ii) and not otherwise subject to Sections I.D.3.b.(ii) or I.D.3.b.(iv) that increases uncontrolled actual emissions to two (2) tons per year VOC based on a rolling twelve-month basis after March 1, 2020, must be in compliance within sixty (60) days of the first day of the month after which the storage tank VOC emissions exceeded two (2) tons per year on a rolling twelve-month basis.
 - I.D.3.b.(vii) If air pollution control equipment is not installed by the applicable compliance date in Sections I.D.3.b.(iii) or I.D.3.b.(v), compliance with Section I.D.3.a.(i) may alternatively be demonstrated by shutting in all wells producing into that storage tank by the date in Sections I.D.3.b.(iii) or I.D.3.b.(v) so long as production does not resume from any such well until the air pollution control equipment is installed and operational.
 - I.D.3.b.(viii) (State Only) If air pollution control equipment is not installed by the applicable compliance date in Sections I.D.3.b.(iv) or I.D.3.b.(vi), compliance with Section I.D.3.a.(ii) may alternatively be demonstrated by shutting in all wells producing into that storage tank by the date in Sections I.D.3.b.(iv) or I.D.3.b.(vi) so long as production does not resume from any such well until the air pollution control equipment is installed and operational.
 - I.D.3.b.(ix) This Section I.D.3. does not apply to storage tanks at natural gas-processing plants subject to Section I.G. or qualifying natural gas compressor stations subject to Section I.I.
- I.D.4. Alternative emissions control equipment and pollution prevention devices and processes installed and implemented after June 1, 2004, shall qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and/or vapor recovery units to achieve the emission reductions required by this Section I.D., if the following conditions are met:
- I.D.4.a. The owner or operator obtains a construction permit authorizing such use of the alternative emissions control equipment or pollution prevention device or process. The proposal for such equipment, device or process shall comply with all regulatory provisions for construction permit applications and shall include the following:
 - I.D.4.a.(i) A description of the equipment, device or process;

- I.D.4.a.(ii) A description of where, when and how the equipment, device or process will be used;
- I.D.4.a.(iii) The claimed control efficiency and supporting documentation adequate to demonstrate such control efficiency;
- I.D.4.a.(iv) An adequate method for measuring actual control efficiency; and
- I.D.4.a.(v) Description of the records and reports that will be generated to adequately track emission reductions and implementation and operation of the equipment, device or process, and a description of how such matters will be reflected in the records and reports required by Section I.F.

I.D.4.b. Public notice of the application is provided pursuant to Regulation Number 3, Part B, Section III.C.4.

I.D.4.c. EPA approves the proposal. The Division shall transmit a copy of the permit application and any other materials provided by the applicant, all public comments, all Division responses and the Division's permit to EPA Region 8. If EPA fails to approve or disapprove the proposal within 45 days of receipt of these materials, EPA shall be deemed to have approved the proposal.

I.E. Monitoring of Storage Tanks and Air Pollution Control Equipment

I.E.1. Applicability

I.E.1.a. The owner or operator of any storage tank that is being controlled pursuant to this Section I. (except storage tanks subject to Section I.D.3.a.(ii)).

I.E.1.b. (State Only) The owner or operator of any storage tank subject to Section I.D.3.a.(ii).

I.E.2. Monitoring Requirements

I.E.2.a. The owner or operator of any storage tank controlled by air pollution control equipment other than a combustion device must follow manufacturer's recommended maintenance. Air pollution control equipment must be periodically inspected to ensure proper maintenance and operation according to the Division-approved operation and maintenance plan.

I.E.2.b. Beginning January 1, 2017, through April 30, 2020, owners or operators of atmospheric condensate storage tanks with uncontrolled actual emissions of VOCs equal to or greater than six (6) tons per year based on a rolling twelve-month total must conduct and document audio, visual, olfactory (AVO) inspections of the storage tank at the same frequency as liquids are loaded out from the storage tank. These inspections are not required more frequently than every seven (7) days but must be conducted at least every thirty-one (31) days.

I.E.2.c. Weekly Monitoring Requirements

The owner or operator must inspect or monitor the air pollution control equipment at least weekly to ensure that it is operating properly. The inspection must include and document the following

- I.E.2.c.(i) For combustion devices, a check that the pilot light is lit by either visible observation or other means approved by the Division. For devices equipped with an auto-igniter, a check that the auto-igniter is properly functioning.
- I.E.2.c.(ii) For combustion devices, a check that the valves for piping of gas to the pilot light are open.
- I.E.2.c.(iii) (State Only) In addition to complying with Sections I.E.2.c.(i). and I.E.2.c.(ii)., the owner or operator of tanks controlled pursuant to Section I.D. that have installed combustion devices may use a surveillance system to maintain records on combustion device operation.
- I.E.2.c.(iv) For combustion devices, the owner or operator must visually check for the presence or absence of smoke and that the burner tray is not visibly clogged.
- I.E.2.c.(v) For vapor recovery units, the owner or operator must check that the unit is operating and that vapors from the storage tank are being routed to the unit.
- I.E.2.c.(vi) For all control devices, the owner or operator must check that the valves for the piping from the storage tank to the air pollution control equipment are open.
- I.E.2.c.(vii) For all storage tanks, the owner or operator must check that the thief hatch is closed and latched, the pressure relief valve is properly seated, and all vent lines are closed.
- I.E.2.c.(viii) Beginning May 1, 2020, or the applicable compliance date in Section I.D.3.b., whichever comes later, owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than four (4) tons per year based on a rolling twelve-month total must conduct audio, visual, olfactory (AVO) inspections of the storage tank.
- I.E.2.c.(ix) (State Only) Beginning May 1, 2020, or the applicable compliance date in Section I.D.3.b., whichever comes later, owners or operators of storage tanks subject to Section I.D.3.a.(ii) must conduct audio, visual, olfactory (AVO) inspections of the storage tank.

I.E.2.d. (State Only) For storage tanks equipped with a surveillance system or other Division-approved monitoring system, the owner or operator must check weekly that the system is functioning properly and that necessary information is being collected. Any loss of data or failure to collect required data may be treated by the Division as if the data were not collected.

I.F. Storage Tank Recordkeeping and Reporting

I.F.1. Recordkeeping and Reporting for Tanks Subject to the System-Wide Control Strategy (through April 30, 2020)

The owner or operator shall, at all times, track the emissions and specifically volatile organic compound emissions reductions on a calendar weekly and calendar monthly basis to demonstrate compliance with the applicable emission reduction requirements of the system-wide control strategy. This shall be done by maintaining a Division-approved spreadsheet of information describing the affected operations, the air pollution control equipment being used, and the emission reductions achieved, as follows.

I.F.1.a. The Division-approved spreadsheet shall:

- I.F.1.a.(i) List all atmospheric condensate storage tanks subject to the system-wide control strategy by name and AIRS number, or if no AIRS number has been assigned the site location. The spreadsheet also shall list the monthly production volumes for each tank. The spreadsheet shall list the most recent measurement of such production at each tank, and the time period covered by such measurement of production.
- I.F.1.a.(ii) List the emission factor used for each atmospheric condensate storage tank. The emission factors shall comply with Section I.C.2.
- I.F.1.a.(iii) List the location and control efficiency value for each unit of air pollution control equipment. Each atmospheric condensate storage tank being controlled shall be identified by name and an AIRS number.
- I.F.1.a.(iv) List the production volume for each tank, expressed as a weekly and monthly average based on the most recent measurement available. The weekly and monthly average shall be calculated by averaging the most recent measurement of such production, which may be the amount shown on the receipt from the refinery purchaser for delivery of condensate from such tank, over the time such delivered condensate was collected. The weekly and monthly average from the most recent measurement will be used to estimate weekly and monthly volumes of controlled and uncontrolled actual emissions for all weeks and months following the measurement until the next measurement is taken.
- I.F.1.a.(v) Show the calendar weekly and calendar monthly-uncontrolled actual emissions and the calendar weekly and calendar monthly controlled actual emissions for each atmospheric condensate storage tank.
- I.F.1.a.(vi) Show the total system-wide calendar weekly and calendar monthly-uncontrolled actual emissions and the total system-wide calendar weekly and calendar monthly controlled actual emissions.
- I.F.1.a.(vii) Show the total system-wide calendar weekly and calendar monthly percentage reduction of emissions.

- I.F.1.a.(viii) Note any downtime of air pollution control equipment, and shall account for such downtime in the weekly control efficiency value and emission reduction totals. The notations shall include the date, time and duration of any scheduled downtime. For any unscheduled downtime, the spreadsheet shall record the date and time the downtime was discovered and the date and time the air pollution control equipment was last observed to be operating.
 - I.F.1.a.(ix) Be maintained in a manner approved by the Division and shall include any other information requested by the Division that is reasonably necessary to determine compliance with the system-wide control strategy.
 - I.F.1.a.(x) Be updated on a calendar weekly and calendar monthly basis and shall be promptly provided by e-mail or fax to the Division upon its request. The U.S. mail may also be used if acceptable to the Division.
- I.F.1.b. Failure to properly install, operate, and maintain air pollution control equipment at the locations indicated in the spreadsheet shall be a violation of this regulation.
- I.F.1.c. A copy of each calendar weekly and calendar monthly spreadsheet shall be retained for five years. A spreadsheet may apply to more than one week if there are no changes in any of the required data and the spreadsheet clearly identifies the weeks it covers. The spreadsheet may be retained electronically. However, the Division may treat any loss of data or failure to maintain the Division-approved spreadsheet, as if the data were not collected.
- I.F.1.d. Each owner or operator shall maintain records of the inspections required pursuant to Section I.E. and retain those records for five years. These records shall include the time and date of the inspection, the person conducting the inspection, a notation that each of the checks required under Sections I.C. and I.E. were completed and a description of any problems observed during the inspection, and a description and date of any corrective actions taken.
- I.F.1.e. (State Only) Each owner or operator shall maintain records of required surveillance system or other monitoring data and shall make these records available promptly upon Division request.
- I.F.1.f. (State Only) Each owner or operator shall maintain records on when an atmospheric condensate storage tank is newly installed, or when a well is newly drilled, re-completed, re-fractured or otherwise stimulated. Records shall be maintained per well associated with each tank and the date of first production associated with these activities.

I.F.1.g. Reporting for Tanks Subject to the System-Wide Control Strategy.

On or before April 30, 2020, each owner or operator shall submit a report describing the air pollution control equipment used during calendar year 2019 and how each company complied with the system-wide control strategy during calendar year 2019. On or before August 30, 2020, each owner or operator must submit a report describing the air pollution control equipment used from January 1, 2020, through April 30, 2020, and how each company complied with the system-wide control strategy during that time period. Such reports shall be submitted to the Division on a Division-approved form provided for that purpose.

- I.F.1.g.(i) The report shall list all condensate storage tanks subject or used to comply with the system-wide control strategy and the production volumes for each tank. Production volumes may be estimated by the amounts shown on the receipt from refinery purchasers for delivery of condensate from such tanks.
- I.F.1.g.(ii) The report shall list the emission factor used for each tank. The emission factors shall comply with Section I.C.2.
- I.F.1.g.(iii) The report shall list the location and control efficiency value for each piece of air pollution control equipment, and shall identify the atmospheric condensate storage tanks being controlled by each.
- I.F.1.g.(iv) The April 30 report shall show the calendar monthly-uncontrolled actual emissions and the controlled actual emissions for each atmospheric condensate storage tank for January 1 through April 30, May 1 through September 30 and October 1 through December 31 of the previous year. The August 30, 2020, report must show the calendar monthly-uncontrolled actual emissions and the controlled actual emissions for each atmospheric condensate storage tank for January 1 through April 30, 2020.
- I.F.1.g.(v) The April 30 report shall show the calendar monthly total system-wide uncontrolled actual emissions and the total system-wide controlled actual emissions for January 1 through April 30, May 1 through September 30 and October 1 through December 31 of the previous year. The August 30, 2020, report must show the calendar monthly total system-wide uncontrolled actual emissions and the total system-wide controlled actual emissions for January 1 through April 30, 2020.
- I.F.1.g.(vi) The April 30 report shall show the calendar monthly total system-wide percentage reduction of emissions for May 1 through September 30 of the previous year, and for the combined periods of January 1 through April 30 and October 1 through December 31 of the previous year. The August 30, 2020, report must show the calendar monthly total system-wide percentage reduction of emissions for January 1 through April 30, 2020.

- I.F.1.g.(vii) The report shall note any downtime of air pollution control equipment, and shall account for such downtime in the weekly control efficiency value and emission reduction totals. The notations shall include the date, time and duration of any scheduled downtime. For any unscheduled downtime, the date and time the downtime was discovered and the last date the air pollution control equipment was observed to be operating should be recorded in the report.
- I.F.1.g.(viii) The report shall state whether the required emission reductions were achieved on a calendar monthly basis during the preceding year for the April 30 report and for January 1 through April 30, 2020, for the August 30 report. If the required emission reductions were not achieved, the report shall state why not, and shall identify steps being taken to ensure subsequent compliance.
- I.F.1.g.(ix) The report shall include any other information requested by the Division that is reasonably necessary to determine compliance with this Section I.
- I.F.1.g.(x) A copy of each semi-annual report shall be retained for five years.
- I.F.1.g.(xi) In addition to submitting the semi-annual reports, on or before the 30th of each month commencing in June 2007 and ending April 30, 2020, the owner or operator of any condensate storage tank that is required to control volatile organic compound emissions pursuant to Sections I.A. and I.D. shall notify the Division of any instances where the air pollution control equipment was not properly functioning during the previous month. The report shall include the time and date that the equipment was not properly operating, the time and date that the equipment was last observed operating properly, and the date and time that the problem was corrected. The report shall also include the specific nature of the problem, the specific steps taken to correct the problem, the AIRS number of each of the condensate tanks being controlled by the equipment or if no AIRS number has been assigned the site name, and the estimated production from those tanks during the period of non-operation.
- I.F.1.g.(xii) Commencing in 2007, on or before April 30 of each year (ending on April 30, 2020), the owner or operator shall submit a list identifying by name and AIRS number or if no AIRS number has been assigned the site name, each condensate storage tank that is being controlled to meet the requirements set forth in Section I.D.1. On the 30th of each month during ozone season (May through September) and on November 30 and February 28 (ending on February 28, 2020), the owner or operator shall submit a list identifying any condensate storage tank whose control status has changed since submission of the previous list.
- I.F.1.g.(xiii) (State Only) Semi-annual report submittals shall be signed by a responsible official who shall also sign the Division-approved

compliance certification form for atmospheric condensate storage tanks. The compliance certification shall include both a certification of compliance with all applicable requirements of Section I. If any non-compliance is identified, citation, dates and durations of deviations from this Section I., associated reasoning, and compliance plan and schedule to achieve compliance. Compliance certifications for state only conditions shall be identified separately from compliance certifications required under the State Implementation Plan.

I.F.1.g.(xiv) (State Only) Each Division-approved self-certification form, and compliance certification submitted pursuant to Section I. shall contain a certification by a responsible official of the truth, accuracy and completeness of such form, report or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

I.F.1.h. The record-keeping and reporting required in Sections I.F.1. shall not apply to the owner or operator of any natural gas compressor station or natural gas drip station that is authorized to operate pursuant to a construction permit or Title V operating permit issued by the Division if the following criteria are met:

I.F.1.h.(i) Such permits are obtained by the owner or operator on or after the effective date of this provision and contain the provisions necessary to ensure the emissions reductions required by Section I.D.;

I.F.1.h.(ii) The owners and operators of such natural gas compressor stations or natural gas drip stations do not own or operate any exploration and production operation(s); and

I.F.1.h.(iii) Total emissions from atmospheric condensate storage tanks associated with such natural gas compressor stations or drip stations subject to APEN reporting requirements under Regulation Number 3, Part A owned or operated by the same person do not exceed 30 tons per year in the 8-hour Ozone Control Area.

I.F.2. Recordkeeping for storage tanks subject to Section I.D.3.

I.F.2.a. The owner or operator of any storage tank subject to control pursuant to Section I.D.3. (except storage tanks subject to Section I.D.3.a.(ii)) must maintain records and make them available to the Division upon request.

I.F.2.b. (State Only) The owner or operator of any storage tank subject to Section I.D.3.a.(ii) must maintain records and make them available to the Division upon request.

I.F.2.c. Records maintained under this Section I.F.2. must include:

I.F.2.c.(i) The AIRS number for the storage tank. The AIRS number assigned by the Division must be marked on all storage tanks required to file an APEN.

- I.F.2.c.(ii) If air pollution control equipment is required to comply with Section I.D.3. visible signage must be located with the control equipment identifying the AIRS number for each storage tank that is being controlled by that equipment.
- I.F.2.c.(iii) Records of the inspections required in Section I.E.
 - I.F.2.c.(iii)(A) The time and date of each inspection.
 - I.F.2.c.(iii)(B) The person conducting the inspection.
 - I.F.2.c.(iii)(C) A notation that each of the checks required under Section I.E. were completed.
 - I.F.2.c.(iii)(D) A description of any problems observed during the inspection, description and date of any corrective actions taken, and name of individual performing corrective actions.
- I.F.2.c.(iv) The calendar monthly uncontrolled actual and controlled actual emissions of VOC and the rolling twelve-month totals for each storage tank subject to control under Section I.D.3.
- I.F.2.c.(v) The emission factor used for each storage tank. The emission factors must comply with Section I.C.2. and the owner or operator must use the most recent emission factor on file with the Division (i.e., either the default emission factor or the specific emission factor established pursuant to Section I.C.2.a.(iii)).
- I.F.2.c.(vi) The control efficiency of each unit of air pollution control equipment and the AIRS number of the storage tank being controlled.
- I.F.2.d. (State Only) The owner or operator of each storage tank subject to Section I.D.3. must maintain records of
 - I.F.2.d.(i) The monthly production volumes for each storage tank, based on the most recent measurement available. The monthly average must be calculated by averaging the most recent measurement of such production, which may be the amount shown on the receipt from the purchaser for delivery of hydrocarbon liquids or produced water from such tank, over the time such delivered hydrocarbon liquids or produced water was collected. The monthly average from the most recent measurement will be used to estimate monthly volumes of controlled and uncontrolled actual emissions for all weeks and months following the measurement until the next measurement is taken.

- I.F.2.d.(ii) Any downtime of air pollution control equipment, including the date, time and duration of any scheduled downtime. For any unscheduled downtime, the date and time the downtime was discovered and the date and time the air pollution control equipment was last observed to be operating.
- I.F.2.d.(iii) Any required surveillance system or other monitoring data.
- I.F.2.d.(iv) When a storage tank is installed, or when a well is drilled, re-completed, re-fractured, or otherwise stimulated. Records must be maintained per well associated with each storage tank and the date of commencement of operation associated with these activities.

I.F.3. Reporting for storage tanks subject to Section I.D.3.

- I.F.3.a. On or before April 30, 2021, and April 30 of each year thereafter, each owner or operator of storage tanks (except storage tanks subject to Section I.D.3.a.(ii)) must submit a report using Division-approved format. A copy of each report must be retained for a period of five (5) years.
- I.F.3.b. (State Only) On or before April 30, 2021, and April 30 of each year thereafter, each owner or operator of storage tanks subject to Section I.D.3.a.(ii) must submit a report using Division-approved format. A copy of each report must be retained for a period of five (5) years.
- I.F.3.c. The report under this Section I.F.3. must include:
 - I.F.3.c.(i) The report must list all storage tanks (by AIRS number and location name) controlled pursuant to Section I.D.3. during the previous calendar year (starting calendar year 2020) and
 - I.F.3.c.(i)(A) The calendar monthly uncontrolled actual and controlled actual emissions of VOC and the rolling twelve-month total for each storage tank.
 - I.F.3.c.(i)(B) The emission factor used for each storage tank for each month.
 - I.F.3.c.(i)(C) The control efficiency for the air pollution control equipment for each storage tank.
 - I.F.3.c.(ii) (State Only) The report must identify any storage tank whose control status has changed, and the date of the change, since submission of the previous report.
 - I.F.3.c.(iii) (State Only) The report must list the production volume for each storage tank. Production volumes may be estimated by the amounts shown on the receipt from the purchaser.

- I.F.3.c.(iv) (State Only) The report must list any downtime of air pollution control equipment, including the date, time, and duration of any scheduled downtime. For any unscheduled downtime, the date and time the downtime was discovered and the last date the air pollution control equipment was observed to be operating must be recorded in the report.
 - I.F.3.c.(v) (State Only) The report must list any instances where the air pollution control equipment was not properly functioning, including the date and time the equipment was not properly operating, the date and time the equipment was last observed operating properly, and the date and time the problem was corrected. The report must also include the specific nature of the problem, the specific steps taken to correct the problem, the AIRS number, or site name if no AIRS number has been assigned, of each storage tank being controlled by the equipment and the estimated production from those storage tanks during the period of non-operation.
 - I.F.3.c.(vi) (State Only) Reports must be signed by a responsible official who must also sign the Division-approved compliance certification form for storage tanks. The compliance certification includes both a certification of compliance with all applicable requirements of Section I. If any non-compliance is identified, the certification must include the citation, dates and durations of deviations from this Section I., associated reasoning, and compliance plan and schedule to achieve compliance. Compliance certifications for state only conditions must be identified separately from compliance certifications required under the State Implementation Plan.
 - I.F.3.c.(vii) (State Only) Each Division-approved self-certification form, and compliance certification submitted pursuant to Section I. must contain a certification by a responsible official of the truth, accuracy and completeness of such form, report or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.
- I.G. Natural gas-processing plants located in the 8-hour Ozone Control Area (State Only: or any specific Ozone Nonattainment or Attainment/Maintenance Area) shall comply with requirements of this Section I.G., as well as the requirements of Sections I.B., I.C.1.a., I.C.1.b., I.H., I.J., I.K., and Part E, Section I.A. through C.
- I.G.1. For fugitive volatile organic compound emissions from leaking equipment, the leak detection and repair (LDAR) program as provided at 40 CFR Part 60, Subpart OOOO (July 1, 2017) applies, regardless of the date of construction of the affected facility, unless subject to the LDAR program provided at 40 CFR Part 60, Subpart OOOOa (July 1, 2017).

- I.G.2. Air pollution control equipment shall be installed and properly operated to reduce emissions of volatile organic compounds from any atmospheric condensate storage tank (or tank battery) used to store condensate that has not been stabilized that has uncontrolled actual emissions of greater than or equal to two tons per year. Such air pollution control equipment shall have a control efficiency of at least 95%.
 - I.G.3. Natural gas processing plants within the 8-hour Ozone Control Area constructed before January 1, 2018, must comply with the requirements of Section I.G. beginning January 1, 2019. (State Only: Existing natural gas processing plants within any new Ozone Nonattainment or Attainment/Maintenance Area shall comply with this regulation within three years after the nonattainment designation.)
 - I.G.4. The provisions of Sections I.B., I.C.1.a., I.C.1.b., I.G., I.H., I.J., I.K., and Part E, Section I.A. through C., apply upon the commencement of operations to any natural gas processing plant that commences operation in the 8-Hour Ozone Control Area or Ozone Nonattainment (State Only: or Attainment/Maintenance Area) after the effective date of this section.
- I.H. Emission Reductions from glycol natural gas dehydrators
- I.H.1. Beginning May 1, 2005, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant in the 8-Hour Ozone Control Area and subject to control requirements pursuant to Section I.H.3., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment.
 - I.H.2. (State Only) Beginning January 30, 2009, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, drip station or gas-processing plant in any Ozone Nonattainment or Attainment/Maintenance Area and subject to control requirements pursuant to Section I.H.3., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment.
 - I.H.3. The control requirements of Sections I.H.1. and I.H.2. apply where:
 - I.H.3.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than one ton per year; and
 - I.H.3.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than one ton per year.
 - I.H.4. For purposes of Section I.H., emissions from still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator shall be calculated using a method approved in advance by the Division.
 - I.H.5. Monitoring and recordkeeping

I.H.5.a. Beginning January 1, 2017, owners or operators of glycol natural gas dehydrators subject to the control requirements of Sections I.H.1. or I.H.2. must check on a weekly basis that any condenser or air pollution control equipment used to control emissions of volatile organic compounds is operating properly, and document:

I.H.5.a.(i) The date of each inspection;

I.H.5.a.(ii) A description of any problems observed during the inspection of the condenser or air pollution control equipment; and

I.H.5.a.(iii) A description and date of any corrective actions taken to address problems observed during the inspection of the condenser or air pollution control equipment.

I.H.5.b. The owner or operator must check and document on a weekly basis that the pilot light on a combustion device is lit, that the valves for piping of gas to the pilot light are open, and visually check for the presence or absence of smoke.

I.H.5.c. The owner or operator must document the maintenance of the condenser or air pollution control equipment, consistent with manufacturer specifications or good engineering and maintenance practices.

I.H.5.d. The owner or operator must retain records for a period of five years and make these records available to the Division upon request.

I.H.6. Reporting

I.H.6.a. On or before November 30, 2017, and semi-annually by April 30 and November 30 of each year thereafter, the owner or operator must submit the following information for the preceding calendar year (April 30 report) and for May 1 through September 30 (November 30 report) using Division-approved format

I.H.6.a.(i) A list of the glycol natural gas dehydrator(s) subject to Section I.H.;

I.H.6.a.(ii) A list of the condenser or air pollution control equipment used to control emissions of volatile organic compounds from the glycol natural gas dehydrator(s); and

I.H.6.a.(iii) The date(s) of inspection(s) where the condenser or air pollution control equipment was found not operating properly or where smoke was observed.

I.I. The requirements of Sections I.D. through I.F. do not apply to the owner or operator of any natural gas compressor station or natural gas drip station located in an Ozone Nonattainment or Attainment/Maintenance Area if:

I.I.1. Air pollution control equipment is installed and properly operated to reduce emissions of volatile organic compounds from all atmospheric condensate storage tanks (or tank batteries) that have uncontrolled actual emissions of greater than or equal to two tons per year;

- I.I.2. The air pollution control equipment is designed to achieve a VOC control efficiency of at least 95% on a rolling 12-month basis and meets the requirements of Sections I.C.1.a. and I.C.1.b;
- I.I.3. The owner or operator of such natural gas compressor station or natural gas drip station does not own or operate any exploration and production facilities in the Ozone Non-attainment or Attainment-maintenance Area; and
- I.I.4. The owner or operator of such natural gas compressor station or natural gas drip station does the following and maintains associated records and reports for a period of five years:
 - I.I.4.a. Documents the maintenance of the air pollution control equipment according to manufacturer specifications;
 - I.I.4.b. Conducts an annual opacity observation once each year on the air pollution control equipment to verify opacity does not exceed 20% during normal operations;
 - I.I.4.c. Maintains records of the monthly stabilized condensate throughput and monthly actual VOC emissions; and
 - I.I.4.d. Reports compliance with these requirements to the Division annually.
- I.I.5. A natural gas compressor station or natural gas drip station subject to Section I.I. at which a glycol natural gas dehydrator and/or natural gas-fired stationary or portable engine is operated is subject to Sections I.H., I.J., and/or Part E, Section I. A natural gas compressor station subject to Section I.I. is also subject to Section I.L.

I.J. Compressors

I.J.1. Centrifugal compressor

- I.J.1.a. Beginning January 1, 2018, uncontrolled actual volatile organic compound emissions from wet seal fluid degassing systems on wet seal centrifugal compressors located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment must be reduced by at least 95%. A centrifugal compressor located at a well production facility, or an adjacent well production facility and servicing more than one well production facility, is not subject to Section I.J.1.
- I.J.1.b. If the owner or operator uses a control device or routes emissions to a process to reduce emissions, the owner or operator must equip the wet seal fluid degassing system with a continuous, impermeable cover that is connected through a closed vent system that routes the emissions from the wet seal fluid degassing system to the process or control device.
- I.J.1.c. The owner or operator must conduct annual visual inspections of the cover and closed vent system for defects that could result in air emissions. Defects of the closed vent system include, but are not limited to, visible cracks, holes, gaps in piping, loose connections, liquid leaks, or broken or missing caps or other closure devices. Defects of the cover include, but are not limited to, visible cracks, holes, gaps in the cover or between the cover and separator wall, broken or damaged seals or gaskets on closure devices, broken or missing hatches or other closure devices.

- I.J.1.d. The owner or operator must conduct annual EPA Method 21 inspections of the cover and closed vent system to determine whether the cover and closed vent system operates with volatile organic compound emissions less than 500 ppm.
- I.J.1.e. In the event that a defect that could result in air emissions or leak is detected, the owner or operator must make a first attempt to repair no later than five (5) days after detecting the defect or leak and complete repair no later than thirty (30) days after detecting the defect or leak.
- I.J.1.f. Owners or operators may delay inspection or repair of a cover or closed vent system if:
 - I.J.1.f.(i) Repair is technically infeasible without a shutdown. If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.
 - I.J.1.f.(ii) The cover or closed vent system is unsafe to inspect or repair because personnel would be exposed to an immediate danger as a consequence of completing the inspection or repair.
 - I.J.1.f.(iii) The cover or closed vent system is difficult to inspect or repair because personnel must be elevated more than two (2) meters above a supported surface or are unable to inspect or repair via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.
 - I.J.1.f.(iv) The cover or closed vent system is inaccessible to inspect or repair because the cover or closed vent system is buried, insulated, or obstructed by equipment or piping that prevents access.
- I.J.1.g. The owner or operator must conduct monthly inspections of a combustion device used to reduce emissions to ensure the device is operating with no visible emissions.
- I.J.1.h. Recordkeeping
 - I.J.1.h.(i) Owners or operators must maintain the following records for at least five (5) years and make records available to the Division upon request:
 - I.J.1.h.(i)(A) Identification of each centrifugal compressor using a wet seal system;
 - I.J.1.h.(i)(B) Each combustion device visible emissions inspection and any resulting responsive actions;
 - I.J.1.h.(i)(C) Each cover and closed vent system inspection and any resulting responsive actions; and
 - I.J.1.h.(i)(D) Each cover or closed vent system on the delay of inspection or repair list, the reason for and duration of the delay of inspection or repair, and the schedule for inspecting or repairing such cover or closed vent system.

I.J.1.i. As an alternative to the inspection, repair, and recordkeeping provisions in Sections I.J.1.c. through I.J.1.f., I.J.1.h.(i)(C), and I.J.1.h.(i)(D), the owner or operator may inspect, repair, and document the cover and closed vent system in accordance with the leak detection and repair program in Section I.L., including the inspection frequency.

I.J.1.j. As an alternative to the emission control, inspection, repair, and recordkeeping provisions described in Sections I.J.1.a. through I.J.1.i., the owner or operator may comply with wet seal centrifugal compressors emission control, monitoring, recordkeeping, and reporting requirements of a New Source Performance Standard in 40 CFR Part 60 (November 16, 2017).

I.J.2. Reciprocating compressor

I.J.2.a. Beginning January 1, 2018, the rod packing on reciprocating compressors located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment must be replaced every 26,000 hours of operation or every thirty-six (36) months. A reciprocating compressor located at a well production facility, or an adjacent well production facility and servicing more than one well production facility, is not subject to Section I.J.2.

I.J.2.a.(i) Owners or operators of reciprocating compressors located at a natural gas processing plant and constructed before January 1, 2018, must

I.J.2.a.(i)(A) Begin monitoring the hours of operation starting January 1, 2018; or

I.J.2.a.(i)(B) Conduct the first rod packing replacement required under Section I.J.2. prior to January 1, 2021.

I.J.2.a.(ii) Owners or operators of reciprocating compressors located at a natural gas processing plant and constructed after January 1, 2018, must begin monitoring the hours or months of operation upon commencement of operation of the reciprocating compressor.

I.J.2.b. As an alternative to the requirement described in Section I.J.2.a., beginning May 1, 2018, the owner or operator may collect rod packing volatile organic compound emissions using a rod packing emissions collection system that operates under negative pressure and routes the rod packing emissions through a closed vent system to a process.

I.J.2.b.(i) The owner or operator must conduct annual visual inspections of the cover and closed vent system for defects that could result in air emissions. Defects of the closed vent system include, but are not limited to, visible cracks, holes, gaps in piping, loose connections, liquid leaks, or broken or missing caps or other closure devices. Defects of the cover include, but are not limited to, visible cracks, holes, gaps in the cover or between the cover and separator wall, broken or damaged seals or gaskets on closure devices, broken or missing hatches or other closure devices.

- I.J.2.b.(ii) The owner or operator must conduct annual EPA Method 21 inspections of the cover and closed vent system to determine whether the cover and closed vent system operates with volatile organic compound emissions less than 500 ppm.
- I.J.2.b.(iii) In the event that a defect that could result in air emissions or leak is detected, the owner or operator must make a first attempt to repair no later than five (5) days after detecting the defect or leak and complete repair no later than thirty (30) days after detecting the defect or leak.
- I.J.2.b.(iv) Owners or operators may delay inspection or repair of a cover or closed vent system if:
 - I.J.2.b.(iv)(A) Repair is technically infeasible without a shutdown. If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.
 - I.J.2.b.(iv)(B) The cover or closed vent system is unsafe to inspect or repair because personnel would be exposed to an immediate danger as a consequence of completing the inspection or repair.
 - I.J.2.b.(iv)(C) The cover or closed vent system is difficult to inspect or repair because personnel must be elevated more than two (2) meters above a supported surface or are unable to inspect or repair via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.
 - I.J.2.b.(iv)(D) The cover or closed vent system is inaccessible to inspect or repair because the cover or closed vent system is buried, insulated, or obstructed by equipment or piping that prevents access.

I.J.2.c. Recordkeeping

- I.J.2.c.(i) Owners or operators must maintain the following records for at least five (5) years and make records available to the Division upon request:
 - I.J.2.c.(i)(A) Identification of each reciprocating compressor;
 - I.J.2.c.(i)(B) The hours of operation or the number of months since the previous rod packing replacement, or a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure;
 - I.J.2.c.(i)(C) The date of each rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system;

I.J.2.c.(i)(D) Each cover and closed vent system inspection and any resulting responsive actions; and

I.J.2.c.(i)(E) Each cover or closed vent system on the delay of inspection or repair list, the reason for and duration of the delay of inspection or repair, and the schedule for inspecting or repairing such cover or closed vent system.

I.J.2.d. As an alternative to the inspection, repair, and recordkeeping provisions in Sections I.J.2.b., I.J.2.c.(i)(D), and I.J.2.c.(i)(E), the owner or operator may inspect, repair, and document the cover and closed vent system in accordance with the leak detection and repair program in Section I.L., including the inspection frequency.

I.J.2.e. As an alternative to the emission control, inspection, repair, and recordkeeping provisions described in Sections I.J.2.a. through I.J.2.d., the owner or operator may comply with reciprocating compressor emission control, monitoring, recordkeeping, and reporting requirements of a New Source Performance Standard in 40 CFR Part 60 (November 16, 2017).

I.K. Pneumatic pumps

I.K.1. Beginning May 1, 2018, the owner or operator of each natural gas-driven diaphragm pneumatic pump located at a natural gas processing plant must ensure the pneumatic pump has a volatile organic compound emission rate of zero.

I.K.2. Beginning May 1, 2018, the owner or operator of each natural gas-driven diaphragm pneumatic pump located at a well production facility must reduce volatile organic compound emissions from the pneumatic pump by 95% if it is technically feasible to route emissions to an existing control device or process at the well production facility. Natural gas-driven diaphragm pneumatic pumps that are in operation during any period of time during a calendar day less than 90 days per calendar year are not subject to Section I.K.2.

I.K.2.a. If the control device available onsite is unable to achieve a 95% emission reduction and it is not technically feasible to route the emissions to a process at the well production facility, the owner or operator must still route the pneumatic pump emissions to the existing control device.

I.K.2.b. If the owner or operator subsequently installs a control device or it becomes technically feasible to route the emissions to a process, the owner or operator must reduce volatile organic compound emissions from the pneumatic pump by 95% within thirty (30) days of startup of the control device or of the feasibility of routing emissions to a process at the well production facility.

I.K.2.c. The owner or operator is not required to control pneumatic pump emissions if, through an engineering assessment by a qualified professional engineer, routing a pneumatic pump to a control device or process at the well production facility is shown to be technically infeasible.

I.K.2.d. If the owner or operator uses a control device or routes emissions to a process to reduce emissions, the owner or operator must connect the pneumatic pump through a closed vent system that routes the pneumatic pump emissions to the process or control device.

I.K.2.e. The owner or operator must conduct annual visual inspections of the closed vent system for defects that could result in air emissions. Defects of the closed vent system include, but are not limited to, visible cracks, holes, gaps in piping, loose connections, liquid leaks, or broken or missing caps or other closure devices.

I.K.2.f. The owner or operators must conduct annual EPA Method 21 inspections of the closed vent system to determine whether the closed vent system operates with volatile organic compound emissions less than 500 ppm.

I.K.2.g. In the event that a defect that could result in air emissions or leak is detected, the owner or operator must make a first attempt to repair no later than five (5) days after detecting the defect or leak and complete repair no later than thirty (30) days after detecting the defect or leak.

I.K.2.h. Owners or operators may delay inspection or repair of a closed vent system if:

I.K.2.h.(i) Repair is technically infeasible without a shutdown. If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

I.K.2.h.(ii) The closed vent system is unsafe to inspect or repair because personnel would be exposed to an immediate danger as a consequence of completing the inspection or repair.

I.K.2.h.(iii) The closed vent system is difficult to inspect or repair because personnel must be elevated more than two (2) meters above a supported surface or are unable to inspect or repair via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

I.K.2.h.(iv) The closed vent system is inaccessible to inspect or repair because the closed vent system is buried, insulated, or obstructed by equipment or piping that prevents access.

I.K.3. Recordkeeping

I.K.3.a. Owners or operators must maintain the following records for at least five (5) years and make records available to the Division upon request:

I.K.3.a.(i) Identification of each natural gas-driven diaphragm pneumatic pump;

I.K.3.a.(ii) For natural gas-driven diaphragm pneumatic pumps in operation less than 90 days per calendar year, records of the days of operation each calendar year;

I.K.3.a.(iii) Records of control devices designed to achieve less than 95% emission reduction, including an evaluation or manufacturer specifications indicating the percentage reduction the control device is designed to achieve;

- I.K.3.a.(iv) Records of the engineering assessment and certification by a qualified professional engineer that routing natural gas-driven diaphragm pneumatic pump emissions to a control device or process is technically infeasible;
 - I.K.3.a.(v) Each closed vent system inspection and any resulting responsive actions; and
 - I.K.3.a.(vi) Each closed vent system on the delay of inspection or repair list, the reason for and duration of the delay of inspection or repair, and the schedule for inspecting or repairing such closed vent system.
- I.K.4. As an alternative to the inspection, repair, and recordkeeping provisions in Sections I.K.2.e. through I.K.2.h., I.K.3.a.(v), and I.K.3.a.(vi), the owner or operator may inspect, repair, and document the closed vent system in accordance with the leak detection and repair program in Section I.L., including the inspection frequency.
- I.K.5. As an alternative to the emission control, inspection, repair, and recordkeeping provisions described in Sections I.K.1. through I.K.4., the owner or operator may comply with natural gas-driven diaphragm pneumatic pump emission control, monitoring, recordkeeping, and reporting requirements of a New Source Performance Standard in 40 CFR Part 60 (November 16, 2017).
- I.L. Leak detection and repair program for well production facilities and natural gas compressor stations located in the 8-hour Ozone Control Area.
 - I.L.1. Natural gas compressor stations
 - I.L.1.a. Beginning June 30, 2018, owners or operators of natural gas compressor stations must inspect components for leaks using an approved instrument monitoring method at least quarterly.
 - I.L.1.b. Owners or operators of natural gas compressor stations constructed on or after June 30, 2018, must conduct an initial inspection for leaks from components using an approved instrument monitoring method no later than ninety (90) days after the facility commences operation. Thereafter, approved instrument monitoring method inspections must be conducted at least quarterly.
 - I.L.2. Well production facilities
 - I.L.2.a. Beginning June 30, 2018, owners or operators of well production facilities with uncontrolled actual volatile organic compound emissions greater than or equal to one (1) ton per year and less than or equal to six (6) tons per year, based on a rolling twelve-month total, must inspect components for leaks using an approved instrument monitoring method at least annually.
 - I.L.2.b. Beginning June 30, 2018, owners or operators of well production facilities with uncontrolled actual volatile organic compound emissions greater than six (6) tons per year, based on a rolling twelve-month total, must inspect components for leaks using an approved instrument monitoring method at least semi-annually.

- I.L.2.c. For purposes of Sections I.L.2.a. and I.L.2.b., the estimated uncontrolled actual volatile organic compound emissions from the highest emitting storage tank at the well production facility determines the frequency at which inspections must be performed. If no storage tanks storing oil or condensate are located at the well production facility, owners or operators must rely on the facility emissions (controlled actual volatile organic compound emissions from all permanent equipment, including emissions from components determined by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates).
 - I.L.2.d. Owners or operators of well production facilities constructed on or after June 30, 2018, must conduct an initial inspection for leaks from components using an approved instrument monitoring method no sooner than fifteen (15) days and no later than thirty (30) days after the facility commences operation. Thereafter, approved instrument monitoring method inspections must be conducted in accordance with Sections I.L.2.a. and I.L.2.b.
- I.L.3. If a component is unsafe, difficult, or inaccessible to monitor, the owner or operator is not required to monitor the component until it becomes feasible to do so.
- I.L.3.a. Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two (2) meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.
 - I.L.3.b. Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.
 - I.L.3.c. Inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.
- I.L.4. Leaks requiring repair: Only leaks from components exceeding the thresholds in Section I.L.4. require repair under Section I.L.5.
- I.L.4.a. For EPA Method 21 monitoring, repair is required for leaks with any concentration of hydrocarbon above 500 ppm not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.
 - I.L.4.b. For infra-red camera monitoring, repair is required for leaks with any detectable emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.
 - I.L.4.c. For other approved instrument monitoring methods or programs, leak identification requiring repair will be established as set forth in an approval under Section I.L.8.

I.L.4.d. For leaks identified using an approved non-quantitative instrument monitoring method, owners or operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section I.L.5. or conducting follow-up monitoring using EPA Method 21 within five (5) working days of the leak detection. If the follow-up EPA Method 21 monitoring shows that the emission is a leak requiring repair as set forth in Section I.L.4.a., the leak must be repaired and remonitored in accordance with Section I.L.5.

I.L.4.e. Owners or operators must maintain and operate approved non-quantitative instrument monitoring methods according to manufacturer recommendations.

I.L.5. Repair and remonitoring

I.L.5.a. First attempt to repair a leak must be made no later than five (5) working days after discovery and completed no later than thirty (30) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists.

I.L.5.a.(i) If parts are unavailable, they must be ordered promptly and the repair must be made within fifteen (15) working days of receipt of the parts.

I.L.5.a.(ii) If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

I.L.5.a.(iii) If delay is attributable to other good cause, repairs must be completed within fifteen (15) working days after the cause of delay ceases to exist.

I.L.5.b. Within fifteen (15) working days of completion of a repair the leak must be remonitored using an approved instrument monitoring method to verify that the repair was effective.

I.L.5.c. Leaks discovered pursuant to the leak detection methods of Section I.L.4. are not subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section I.L.5. or keep required records in accordance with Section I.L.6.

I.L.6. Recordkeeping

I.L.6.a. Documentation of the initial approved instrument monitoring method inspection for well production facilities and natural gas compressor stations;

I.L.6.b. The date, facility name, and facility AIRS ID or facility location if the facility does not have an AIRS ID for each inspection;

I.L.6.c. A list of the leaks requiring repair and the monitoring method(s) used to determine the presence of the leak;

I.L.6.d. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair;

I.L.6.e. The date the leak was repaired and type of repair method applied;

- I.L.6.f. The delayed repair list, including the date and duration of any period where the repair of a leak was delayed due to unavailable parts, required shutdown, or delay for other good cause, the basis for the delay, and the schedule for repairing the leak. Delay of repair beyond thirty (30) days after initial discovery due to unavailable parts must be reviewed, and a record kept of that review, by a representative of the owner or operator with responsibility for leak detection and repair compliance functions. This review will not be made by the individual making the initial determination to place a part on the delayed repair list;
 - I.L.6.g. The date the leak was remonitored and the results of the remonitoring; and
 - I.L.6.h. A list of components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section I.L.3., an explanation stating why the component is so designated, and the schedule for monitoring such component(s).
 - I.L.6.i. Records must be maintained for a minimum of five years and made available to the Division upon request.
- I.L.7. Reporting: The owner or operator of each facility subject to the leak detection and repair requirements in Section I.L. must submit a single annual report on or before May 31st of each year (beginning May 31st, 2019) that includes, at a minimum, the following information regarding leak detection and repair activities at their subject facilities conducted the previous calendar year:
- I.L.7.a. The total number of well production facilities and total number of natural gas compressor stations inspected;
 - I.L.7.b. The total number of inspections performed per inspection frequency tier of well production facilities and the total number of inspections performed at natural gas compressor stations;
 - I.L.7.c. The total number of identified leaks requiring repair broken out by component type, monitoring method, and inspection frequency tier of well production facility as reported in Section I.L.7.b. and the total number of identified leaks requiring repair at natural gas compressor stations broken out by component type and monitoring method;
 - I.L.7.d. The total number of leaks repaired for each inspection frequency tier of well production facilities as reported in Section I.L.7.b. and the total number of leaks repaired for natural gas compressor stations;
 - I.L.7.e. The total number of leaks on the delayed repair list as of December 31st broken out by component type, inspection frequency tier of well production facility as reported in Section I.L.7.b. or natural gas compressor station, and the basis for each delay of repair;
 - I.L.7.f. The record of all reviews conducted for delayed repairs due to unavailable parts extending beyond 30 days for the previous calendar year; and
 - I.L.7.g. Each report shall be accompanied by a certification by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.
- I.L.8. Alternative approved instrument monitoring methods may be used in lieu of, or in combination with an infra-red camera, EPA Method 21, or other approved instrument

monitoring method to inspect for leaks as required by Section I.L., if the following conditions are met:

I.L.8.a. The proponent of the alternative approved instrument monitoring method applies for a determination of an alternative approved instrument monitoring method or program. The application must include, at a minimum, the following:

- I.L.8.a.(i) The proposed alternative approved instrument monitoring method manufacturer information;
- I.L.8.a.(ii) A description of the proposed alternative approved instrument monitoring method including, but not limited to:
 - I.L.8.a.(ii)(A) Whether the proposed alternative approved instrument monitoring method is a quantitative detection method, and how emissions are quantified, or qualitative leak detection method;
 - I.L.8.a.(ii)(B) Whether the proposed alternative approved instrument monitoring method is commercially available;
 - I.L.8.a.(ii)(C) Whether the proposed alternative approved instrument monitoring method is approved by other regulatory authorities and for what application (e.g., pipeline monitoring, emissions detected);
 - I.L.8.a.(ii)(D) The leak detection capabilities, reliability, and limitations of the proposed alternative approved instrument monitoring method, including, but not limited to, the ability to identify specific leaks or locations, detection limits, and any restrictions on use, as well as supporting data;
 - I.L.8.a.(ii)(E) The frequency of measurements and data logging capabilities of the proposed alternative approved instrument monitoring method;
 - I.L.8.a.(ii)(F) Data quality indicators for precision and bias of the proposed alternative approved instrument monitoring method;
 - I.L.8.a.(ii)(G) Quality control and quality assurance procedures necessary to ensure proper operation of the proposed alternative approved instrument monitoring method;
 - I.L.8.a.(ii)(H) A description of where, when, and how the proposed alternative approved instrument monitoring method will be used; and

- I.L.8.a.(ii)(I) Documentation (e.g., field or test data, modeling) adequate to demonstrate the proposed alternative approved instrument monitoring method or program is capable of achieving emission reductions that are at least as effective as the emission reductions achieved by the leak detection and repair provisions in Section I.L.
- I.L.8.a.(iii) The Division will transmit a copy of the complete application and any other materials provided by the applicant to EPA.
- I.L.8.a.(iv) Public notice of the application is provided pursuant to Regulation Number 3, Part B, Section III.C.4.
- I.L.8.a.(v) The Division and the EPA approves the proposal. The Division will transmit a copy of the application and any other materials provided by the applicant, all public comments, all Division responses and the Division's approval to EPA Region 8. If EPA fails to approve or disapprove the proposal within six (6) months of receipt of these materials, EPA will be deemed to have approved the proposal.

II. (State Only) Statewide Controls for Oil and Gas Operations

II.A. (State Only) Definitions

- II.A.1. "Air Pollution Control Equipment," as used in this Section II., means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment and pollution prevention devices and processes intended to reduce uncontrolled actual emissions that comply with the requirements of Section II.B.2.e.
- II.A.2. "Approved Instrument Monitoring Method," means an infra-red camera, EPA Method 21, or other Division approved instrument based monitoring method or program. If an owner or operator elects to use Division approved continuous emission monitoring, the Division may approve a streamlined inspection and reporting program for such operations.
- II.A.3. "Auto-Igniter" means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust VOC emissions.
- II.A.4. "Centrifugal Compressor" means any machine used for raising the pressure of natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors.
- II.A.5. "Class II Disposal Well Facility" means a facility that injects underground fluids which are brought to the surface in connection with natural gas storage operations or oil or natural gas production and that may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection. Class II disposal well facilities do not include wells which inject fluids for enhanced recovery of oil or natural gas or for storage of hydrocarbons which are liquid at standard temperature and pressure.

- II.A.6. "Commencement of operation" means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).
- II.A.7. "Component" means each pump seal, flange, pressure relief device (including thief hatches or other openings on a controlled storage tank), connector, and valve that contains or contacts a process stream with hydrocarbons, except for components in process streams consisting of glycol, amine, produced water, or methanol.
- II.A.8. "Connector" means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors.
- II.A.9. "Dump Valve" means a liquid-control valve in a separator that controls liquid level within the separator vessel.
- II.A.10. "Dump Event" means the opening of a dump valve allowing liquid to flow from a separator equipped with a dump valve to a storage tank.
- II.A.11. "Glycol Natural Gas Dehydrator" means any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.
- II.A.12. "Infra-red Camera" means an optical gas imaging instrument designed for and capable of detecting hydrocarbons.
- II.A.13. "Hydrocarbon Liquid" means any naturally occurring, unrefined petroleum liquid. Hydrocarbon liquid does not include produced water.
- II.A.14. "Natural Gas Compressor Station" means a facility, located downstream of well production facilities, which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure prior to the inlet of a natural gas processing plant.
- II.A.15. "Normal Operation" means all periods of operation, excluding malfunctions as defined in Section I.G. of the Common Provisions regulation. For storage tanks at well production facilities, normal operation includes but is not limited to liquid dumps from the separator.
- II.A.16. "Occupied Areas" means (1) a building or structure designed for use as a place of residency by a person, a family, or families. The term includes manufactured, mobile, and modular homes, except to the extent that any such manufactured, mobile, or modular home is intended for temporary occupancy or for business purposes; (2) indoor or outdoor spaces associated with a school that students use commonly as part of their curriculum or extracurricular activities; (3) five thousand (5,000) or more square feet of building floor area in commercial facilities that are operating and normally occupied during working hours; and (4) an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of outdoor public assembly.

- II.A.17. "Open-Ended Valve or Line" means any valve, except safety relief valves, having one side of the valve seat in contact with process fluid and one side open to the atmosphere, either directly or through open piping.
- II.A.18. "Produced Water" means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.
- II.A.19. "Reciprocating Compressor" means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of the piston rod.
- II.A.20. "Stabilized" when used to refer to crude oil, condensate, intermediate hydrocarbon liquids, or produced water means that the vapor pressure of the liquid is sufficiently low to prevent the production of vapor phase upon transferring the liquid to an atmospheric pressure in a storage tank, and that any emissions that occur are limited to those commonly referred to within the industry as working, breathing, and standing losses.
- II.A.21. "Storage Tank" means any fixed roof storage vessel or series of storage vessels that are manifolded together via liquid line. Storage tanks may be located at a well production facility or other location.
- II.A.22. "Storage Tank Measurement System" means equipment and methods used to determine the quantity and quality of the liquids inside a storage tank without requiring direct access through the storage tank thief hatch.
- II.A.23. "Storage Vessel" means a tank or other vessel that contains an accumulation of hydrocarbon liquids or produced water and is constructed primarily of nonearthed materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after commencement of operation for a period which exceeds 60 days is considered a storage vessel. Storage vessel does not include vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and are intended to be located at the site for less than 180 consecutive days; process vessels such as surge control vessels, bottom receivers, or knockout vessels; or pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.
- II.A.24. "Visible Emissions" means observations of smoke for any period or periods of duration greater than or equal to one (1) minute in any fifteen (15) minute period during normal operation, pursuant to EPA Method 22. Visible emissions do not include radiant energy or water vapor.
- II.A.25. "Vapor Collection and Return System" means a closed system designed to control the release of VOCs displaced from a vessel during transfer of hydrocarbon liquids by using the transferred hydrocarbon liquids for direct displacement to force vapors from the vessel being loaded into either the storage tank being unloaded or to air pollution control equipment.
- II.A.26. "Well Production Facility" means all equipment at a single stationary source directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

II.B. (State Only) General Provisions

II.B.1. General requirements for prevention of emissions and good air pollution control practices for all oil and gas exploration and production operations, Class II disposal well facilities, well production facilities, natural gas compressor stations, and natural gas processing plants.

II.B.1.a. All hydrocarbon liquids and produced water collection, storage, processing, and handling operations, regardless of size, must be designed, operated, and maintained so as to minimize emission of VOCs and other hydrocarbons to the atmosphere to the extent reasonably practicable.

II.B.1.b. At all times, including periods of start-up and shutdown, the facility and air pollution control equipment must be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether or not acceptable operation and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operation and maintenance procedures, and inspection of the source.

II.B.2. General requirements for air pollution control equipment used to comply with Section II.

II.B.2.a. All air pollution control equipment must be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator must keep manufacturer specifications or equivalent on file. In addition, all such air pollution control equipment must be adequately designed and sized to achieve the control efficiency rates and to handle reasonably foreseeable fluctuations in emissions of VOCs and other hydrocarbons during normal operations. Fluctuations in emissions that occur when the separator dumps into the tank are reasonably foreseeable.

II.B.2.b. If a combustion device is used to control emissions of VOCs and other hydrocarbons, it must be enclosed, have no visible emissions during normal operation, and be designed so that an observer can, by means of visual observation from the outside of the enclosed combustion device, or by other means approved by the Division, determine whether it is operating properly.

II.B.2.c. Any of the effective dates for installation of controls on storage tanks, dehydrators, and/or internal combustion engines may be extended at the Division's discretion for good cause shown.

II.B.2.d. Auto-igniters: All combustion devices used to control emissions of hydrocarbons must be equipped with and operate an auto-igniter as follows

II.B.2.d.(i) All combustion devices installed on or after May 1, 2014, must be equipped with an operational auto-igniter upon installation of the combustion device.

II.B.2.d.(ii) All combustion devices installed before May 1, 2014, must be equipped with an operational auto-igniter by or before May 1, 2016, or after the next combustion device planned shutdown, whichever comes first.

II.B.2.e. Alternative emissions control equipment will qualify as air pollution control equipment, and may be used in lieu of, or in combination with, combustion devices and vapor recovery units to achieve the emission reductions required by this Section II., if the Division approves the equipment, device, or process. As part of the approval process the Division, at its discretion, may specify a different control efficiency than the control efficiencies required by this Section II.

II.B.3. Requirements for compressor seals and open-ended valves or lines

II.B.3.a. Beginning January 1, 2015, each open-ended valve or line at well production facilities and natural gas compressor stations must be equipped with a cap, blind flange, plug, or a second valve that seals the open end at all times except during operations requiring process fluid flow through the open-ended valve or line. Open-ended valves or lines in an emergency shutdown system which are designed to open automatically in the event of a process upset are exempt from the requirement to seal the open end of the valve or line. Alternatively, an open-ended valve or line may be treated as if it is a "component" as defined in Section II.A.7., and may be monitored under the provisions of Section II.E.

II.B.3.b. Beginning January 1, 2015, uncontrolled actual hydrocarbon emissions from wet seal fluid degassing systems on wet seal centrifugal compressors must be reduced by at least 95%, unless the centrifugal compressor is subject to 40 CFR Part 60, Subpart OOOO (February 23, 2014) on that date or thereafter.

II.B.3.c. Beginning January 1, 2015, the rod packing on any reciprocating compressor located at a natural gas compressor station must be replaced every 26,000 hours of operation or every thirty-six (36) months, unless the reciprocating compressor is subject to 40 CFR Part 60, Subpart OOOO (February 23, 2014) on that date or thereafter. The measurement of accumulated hours of operation (26,000) or months elapsed (36) begins on January 1, 2015.

II.B.4. Oil refineries are not subject to Section II.

II.B.5. Glycol natural gas dehydrators that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63 (December 17, 2006), a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard ("NSPS") under 40 CFR Part 60 (December 17, 2006) are not subject to Section II., except for the leak detection and repair requirements in Section II.E.

II.C. Emission reduction from storage tanks at oil and gas exploration and production operations, Class II disposal well facilities, well production facilities, natural gas compressor stations, and natural gas processing plants.

II.C.1. Control and monitoring requirements for storage tanks

II.C.1.a. (State Only) Beginning May 1, 2008, owners or operators of all storage tanks storing condensate with uncontrolled actual emissions of VOCs equal to or greater than twenty (20) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that has a control efficiency of at least 95% for VOCs.

II.C.1.b.(State Only) Owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than six (6) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves a hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons, except where the combustion device has been authorized by permit prior to May 1, 2014.

II.C.1.b.(i) (State Only) Control requirements of Section II.C.1.b. must be achieved in accordance with the following schedule:

II.C.1.b.(i)(A) A storage tank constructed on or after May 1, 2014, must be in compliance within ninety (90) days of the date that the storage tank commences operation.

II.C.1.b.(i)(B) A storage tank constructed before May 1, 2014, must be in compliance by May 1, 2015.

II.C.1.b.(i)(C) A storage tank not otherwise subject to Sections II.C.1.b.(i)(A) or II.C.1.b.(i)(B) that increases uncontrolled actual emissions to six (6) tons per year VOC or more on a rolling twelve-month basis after May 1, 2014, must be in compliance within sixty (60) days of discovery of the emissions increase.

II.C.1.b.(ii). Control requirements within ninety (90) days of commencement of operation.

II.C.1.b.(ii)(A) Beginning May 1, 2014, through March 1, 2020, owners or operators of storage tanks at well production facilities must collect and control emissions by routing emissions to operating air pollution control equipment during the first ninety (90) calendar days after commencement of operation. The air pollution control equipment must achieve a hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons. This control requirement does not apply to storage tanks that are projected to have emissions less than 1.5 tons of VOC during the first ninety (90) days after commencement of operation.

II.C.1.b.(ii)(B) The air pollution control equipment and any associated monitoring equipment required pursuant to Section II.C.1.c.(i) may be removed at any time after the first ninety (90) calendar days as long as the source can demonstrate that uncontrolled actual emissions from the storage tank will be below the threshold in Section II.C.1.b.

II.C.1.c. (State Only) Owners or operators of storage tanks with uncontrolled actual emissions of VOCs equal to or greater than two (2) tons per year based on a rolling twelve-month total must collect and control emissions from each storage tank by routing emissions to and operating air pollution control equipment that achieves a hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons, except where the combustion device has been authorized by permit prior to March 1, 2020.

II.C.1.c.(i) Control requirements of Section II.C.1.c. must be achieved in accordance with the following schedule

II.C.1.c.(i)(A) A storage tank constructed on or after March 1, 2020, must be in compliance by commencement of operation of that storage tank.

II.C.1.c.(i)(B) A storage tank constructed before March 1, 2020, that is not already controlled under Sections I.D. or II.C.1.b. must be in compliance by May 1, 2021.

II.C.1.c.(i)(C) A storage tank not otherwise subject to Sections II.C.1.c.(i)(A) or II.C.1.c.(i)(B) that increases uncontrolled actual emissions above the applicable threshold in Section II.C.1.c.(i)(B) after the applicable date in Section II.C.1.c.(i)(B) must be in compliance within sixty (60) days of the first day of the month after which the storage tank emissions exceeded the applicable threshold based on a rolling twelve-month basis.

II.C.1.c.(ii) If air pollution control equipment is not installed by the applicable compliance date in Sections II.C.1.c.(i)(A), II.C.1.c.(i)(B), or II.C.1.c.(i)(C), compliance with Section II.C.1.c. may alternatively be demonstrated by shutting in all wells producing into that storage tank by the date in Sections II.C.1.c.(i)(A), II.C.1.c.(i)(B), or II.C.1.c.(i)(C) so long as production does not resume from any such well until the air pollution control equipment is installed and operational.

II.C.1.c.(iii) Owners or operators of storage tanks for which the use of air pollution control equipment would be technically infeasible without supplemental fuel may apply to the Division for an exemption from the control requirements of Section II.C.1.c. Such request must include documentation demonstrating the infeasibility of the air pollution control equipment. The applicability of this exemption does not relieve owners or operators of compliance with the storage tank monitoring requirements of Section II.C.1.d.

II.C.1.d.(State Only) Beginning May 1, 2014, or the applicable compliance date in Sections II.C.1.b.(i) or II.C.1.c.(i), whichever comes later, owners or operators of storage tanks subject to Section II.C.1. must conduct audio, visual, olfactory (AVO) and additional visual inspections of the storage tank and any associated equipment (e.g., separator, air pollution control equipment, or other pressure reducing equipment) at the same frequency as liquids are loaded out from the storage tank. These inspections are not required more frequently than every seven (7) days but must be conducted at least every thirty-one (31) days. Monitoring is not required for storage tanks or associated equipment that are unsafe, difficult, or inaccessible to monitor, as defined in Section II.C.1.e. The additional visual inspections must include, at a minimum:

- II.C.1.d.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly sealed.
- II.C.1.d.(ii) Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating, including that the pilot light is lit on combustion devices used as air pollution control equipment.
- II.C.1.d.(iii) If a combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light to ensure they are functioning properly.
- II.C.1.d.(iv) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the storage tank to the air pollution control equipment are open.
- II.C.1.d.(v) If a combustion device is used, inspection of the device for the presence or absence of smoke. If smoke is observed, either the equipment must be immediately shut-in to investigate the potential cause for smoke and perform repairs, as necessary, or EPA Method 22 must be conducted to determine whether visible emissions are present for a period of at least one (1) minute in fifteen (15) minutes.
- II.C.1.d.(vi) Beginning May 1, 2020, or the applicable compliance date in Section II.C.1.c.(i), whichever comes later, visual observation of the dump valve(s) of the last separator(s) before the storage tank(s) to ensure the dump valve is free of debris and not stuck open. The owner or operator is not required to observe the actuation of the dump valve during this inspection; however, if a dump event occurs during the inspection, the owner or operator must confirm proper operation of the valve.
- II.C.1.d.(vii) Beginning May 1, 2020, or the applicable compliance date in Section II.C.1.c.(i), whichever comes later, a check for the presence of liquids in liquid knockout vessels that do not drain automatically, underground lines, and aboveground piping.

II.C.1.d.(vii)(A) For liquid knockout vessels for which a procedure exists to check liquid level, check for the presence of liquids. If liquids are present above the low level indication point, drain liquids.

II.C.1.d.(vii)(B) For liquid knockout vessels for which no procedure exists to check liquid level, drain liquids.

II.C.1.d.(vii)(C) For underground lines and aboveground piping that is not sloped to a liquid knockout or tank and for which a procedure exists to check for the presence of liquids accumulation, check for the presence of liquids and drain liquids as needed.

II.C.1.d.(vii)(D) For underground lines and aboveground piping that is not sloped to a liquid knockout vessel or tank and for which no written procedure exists to check for the presence of liquids accumulation, drain liquids quarterly.

II.C.1.e. (State Only) If storage tanks or associated equipment is unsafe, difficult, or inaccessible to monitor, the owner or operator is not required to monitor such equipment until it becomes feasible to do so.

II.C.1.e.(i) Difficult to monitor means it cannot be monitored without elevating the monitoring personnel more than two meters above a supported surface or is unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access up to 7.6 meters (25 feet) above the ground.

II.C.1.e.(ii) Unsafe to monitor means it cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

II.C.1.e.(iii) Inaccessible to monitor means buried, insulated, or obstructed by equipment or piping that prevents access by monitoring personnel.

II.C.2. (State Only) Capture and monitoring requirements for storage tanks that are fitted with air pollution control equipment as required by Sections I.D. or II.C.1.

II.C.2.a. Owners or operators of storage tanks must route all hydrocarbon emissions to air pollution control equipment, and must operate without venting hydrocarbon emissions from the thief hatch (or other access point to the tank) or pressure relief device during normal operation, unless venting is reasonably required for maintenance, gauging (unless the use of a storage tank measurement system is required pursuant to and the operator complies with Section II.C.4.), or safety of personnel and equipment. Compliance must be achieved in accordance with the schedule in Section II.C.2.b.(ii).

II.C.2.a.(i) Venting is emissions from a controlled storage tank thief hatch, pressure relief device, or other access point to the storage tank, which:

- II.C.2.a.(i)(A) Are primarily the result of over-pressurization, whether related to design, operation, or maintenance; or
- II.C.2.a.(i)(B) Are the result of an open, unlatched, or visibly unseated pressure relief device (e.g., thief hatch or pressure relief valve), an open vent line, or an unintended opening in the storage tank (e.g., crack or hole).
- II.C.2.a.(ii) When emissions from a controlled storage tank are observed, the Division may require the owner or operator to submit sufficient information demonstrating whether or not the emissions were primarily the result of over-pressurization. Absent a demonstration that such emissions were not primarily the result of over-pressurization, such emissions will be considered venting for purposes of Section II.C.2.a.
- II.C.2.a.(iii) When venting is observed, the owner or operator must confirm within twenty-four (24) hours of taking action to return the storage tank to operation without venting that the action(s) taken was effective. If the venting was observed using an approved instrument monitoring method, the confirmation must be made using an approved instrument monitoring method.
- II.C.2.b. Owners or operators of storage tanks subject to the control requirements of Sections I.D., II.C.1.a, II.C.1.b., or II.C.1.c. must develop, certify, and implement a documented Storage Tank Emission Management System (STEM) plan to identify, evaluate, and employ appropriate control technologies, monitoring practices, operational practices, and/or other strategies designed to meet the requirements set forth in Section II.C.2.a. Owners or operators must update the STEM plan as necessary to achieve or maintain compliance. Owners or operators are not required to develop and implement STEM for storage tanks containing only stabilized liquids. The minimum elements of STEM are listed.
 - II.C.2.b.(i) STEM plans must include selected control technologies, monitoring practices, operational practices, and/or other strategies; an analysis of the engineering design of the storage tank and air pollution control equipment; procedures for evaluating ongoing storage tank emission capture performance; and monitoring in accordance with approved instrument monitoring methods following the applicable schedule in Section II.C.2.b.(ii).
 - II.C.2.b.(ii) Owners or operators must achieve the requirements of Sections II.C.2.a. and II.C.2.b. and begin implementing the required approved instrument monitoring method in accordance with the following schedule

- II.C.2.b.(ii)(A) A storage tank subject to Sections II.C.1.a. or II.C.1.b. and constructed on or after May 1, 2014, must comply with the requirements of Section II.C.2.a. by the date the storage tank commences operation. The storage tank must comply with Section II.C.2.b. and implement the approved instrument monitoring method inspections within ninety (90) days of the date that the storage tank commences operation.
- II.C.2.b.(ii)(B) A storage tank subject to Sections II.C.1.a. or II.C.1.b. and constructed before May 1, 2014, must comply with the requirements of Sections II.C.2.a. and II.C.2.b. by May 1, 2015.
- II.C.2.b.(ii)(C) A storage tank subject to Section II.C.1.c. and constructed on or after March 1, 2020, must comply with the requirements of Section II.C.2.a. by commencement of operation of the storage tank. The storage tank must comply with Section II.C.2.b. and implement the approved instrument monitoring method inspections within ninety (90) days of commencement of operation of the storage tank.
- II.C.2.b.(ii)(D) A storage tank subject to Sections II.C.1.c. and I.D.3. and constructed before March 1, 2020, that is not subject to the control requirements of the system-wide control strategy in Section I.D.1. must comply with the requirements of Sections II.C.2.a. and II.C.2.b. by May 1, 2020, or by commencement of operation of the storage tank, whichever comes later.
- II.C.2.b.(ii)(E) A storage tank subject to Section II.C.1.c. and constructed before March 1, 2020, that is not subject to the control requirements of the system-wide control strategy in Section I.D.1. must comply with the requirements of Sections II.C.2.a. and II.C.2.b. by May 1, 2021. Approved instrument monitoring method inspections of the storage tank must begin in 2021.
- II.C.2.b.(ii)(F) A storage tank with uncontrolled actual emissions of VOCs equal to or greater than six (6) and less than or equal to twelve (12) tons per year must begin semi-annual approved instrument monitoring method inspections in 2020.

- II.C.2.b.(ii)(G) A storage tank not otherwise subject to Sections II.C.2.b.(ii)(A) or II.C.2.b.(ii)(B) that increases uncontrolled actual emissions to six (6) tons per year VOC or more on a rolling twelve month basis after May 1, 2014, must comply with the requirements of Sections II.C.2.a. and II.C.2.b. and implement the required approved instrument monitoring method inspections within sixty (60) days of the first day of the month after which the storage tank emissions exceeded the applicable threshold based on a rolling twelve-month basis..
- II.C.2.b.(ii)(H) A storage tank not otherwise subject to Sections II.C.2.b.(ii)(A) through II.C.2.b.(ii)(F) that increases uncontrolled actual emissions above the applicable threshold in Section II.C.1.c.(i)(B) after the applicable date in Section II.C.1.c.(i)(B), must comply with the requirements of Sections II.C.2.a. and II.C.2.b. and implement the required approved instrument monitoring method inspections within sixty (60) days of the first day of the month after which the storage tank VOC emissions exceeded the applicable threshold based on a rolling twelve-month basis.
- II.C.2.b.(ii)(I) Following the first approved instrument monitoring method inspection, owners or operators must continue conducting approved instrument monitoring method inspections in accordance with the inspection frequency in Table 1.

Table 1 – Storage Tank Inspections	
Threshold: Storage Tank Uncontrolled Actual VOC Emissions (tpy)	Approved Instrument Monitoring Method Inspection Frequency
> 2 and ≤ 12	Semi-annually
> 12 and ≤ 50	Quarterly
> 50	Monthly

- II.C.2.b.(iii) Owners or operators are not required to monitor storage tanks and associated equipment that are unsafe, difficult, or inaccessible to monitor, as defined in Section II.C.1.e.
- II.C.2.b.(iv) STEM must include a certification by the owner or operator that the selected STEM strategy(ies) are designed to minimize emissions from storage tanks and associated equipment at the facility(ies), including thief hatches and pressure relief devices.

II.C.3. (State Only) Recordkeeping: The owner or operator of each storage tank subject to Sections I.D. or II.C. must maintain records of STEM, if applicable, including the plan, any updates, and the certification, and make them available to the Division upon request. In addition, for a period of two (2) years, the owner or operator must maintain records of any required monitoring and make them available to the Division upon request, including

II.C.3.a. The AIRS ID for the storage tank.

II.C.3.b. The date and duration of any period where the thief hatch, pressure relief device, or other access point are found to be venting hydrocarbon emissions, except for venting that is reasonably required for maintenance, gauging (unless use of a storage tank measurement system is required pursuant to and the operator complies with Section II.C.4.), or safety of personnel and equipment.

II.C.3.c. The date and duration of any period where the air pollution control equipment is not operating.

II.C.3.d. Records of the inspections required in Sections II.C.1.d. and II.C.2.b.(ii), including the time and date of each inspection and a description of any problems observed, description and date of any corrective action(s) taken, and name of employee or third party performing corrective action(s).

II.C.3.e. Where a combustion device is being used, the date and result of any EPA Method 22 test or investigation pursuant to Section II.C.1.d.(v).

II.C.3.f. The timing of and efforts made to eliminate venting, restore operation of air pollution control equipment, and mitigate visible emissions, including the dates and results of action(s) taken and the monitoring used to confirm the action(s) were successful.

II.C.3.g. A list of equipment associated with the storage tank that is designated as unsafe, difficult, or inaccessible to monitor, as described in Section II.C.1.e., an explanation stating why the equipment is so designated, and the plan for monitoring such equipment.

II.C.3.h. Records of any exemption, and associated documentation, applied for under Section II.C.1.c.(iii).

II.C.4. (State Only) Storage tank measurement system requirements at well production facilities, natural gas compressor stations, and natural gas processing plants

II.C.4.a. Applicability

II.C.4.a.(i) The owners or operators of controlled storage tanks at well production facilities, natural gas compressor stations, or natural gas processing plants constructed on or after May 1, 2020, and at any facilities that are modified on or after May 1, 2020, such that an additional controlled storage vessel is constructed to receive an anticipated increase in throughput of hydrocarbon liquids or produced water, must use a storage tank measurement system to determine the quantity of liquids in the storage tank(s).

- II.C.4.a.(ii) The owners or operators of controlled storage tanks at well production facilities, natural gas compressor stations, or natural gas processing plants constructed on or after January 1, 2021, and at any facilities that are modified on or after January 1, 2021, such that an additional controlled storage vessel is constructed to receive an anticipated increase in throughput of hydrocarbon liquids or produced water, must use a storage tank measurement system to determine the quality and quantity of liquids in the storage tank(s).
- II.C.4.b. Owner or operators subject to the storage tank measurement system requirements in Section II.C.4.a., must keep thief hatches (or other access points to the tank) and pressure relief devices on storage tanks closed and latched during activities to determine the quality and/or quantity of liquids in the storage tank(s).
- II.C.4.c. Operators may inspect, test, and/or calibrate the storage tank measurement system semi-annually, or as directed by the Bureau of Land Management (see 43 CFR Section 3174.6(b)(5)(ii)(B) (November 17, 2016)) or system manufacturer. Opening the thief hatch if required to inspect, test, or calibrate the system is not a violation of Section II.C.4.b.
- II.C.4.d. The owner or operator must install signage at or near the storage tank that indicates which equipment and method(s) is used and the appropriate and necessary operating procedures for that system.
- II.C.4.e. The owner or operator must develop and implement an annual training program for employees and/or third parties conducting activities subject to Section II.C.4. that includes, at a minimum, operating procedures for each type of system.
- II.C.4.f. Owner or operators must retain records for at least two (2) years and make such records available to the Division upon request, including
 - II.C.4.f.(i) Date of construction of the storage vessel or facility.
 - II.C.4.f.(ii) Description of the storage tank measurement system used to comply with Section II.C.4.a.
 - II.C.4.f.(iii) Date(s) of storage tank measurement system inspections, testing, and/or calibrations pursuant to Section II.C.4. c.
 - II.C.4.f.(iv) Manufacturer specifications regarding storage tank measurement system inspections, and/or calibrations, if followed pursuant to Section II.C.4.c.
 - II.C.4.f.(v) Records of the annual training program, including the date and names of persons trained.
- II.C.5. (State Only) Storage tank hydrocarbon liquids loadout requirements at Class II disposal well facilities, well production facilities, natural gas compressor stations, and natural gas processing plants

- II.C.5.a. Owners or operators of well production facilities, natural gas compressor stations, and natural gas processing plants with a hydrocarbon liquids loadout to transport vehicles throughput of greater than or equal to 5,000 barrels per year on a rolling 12-month basis must control emissions from the loadout of hydrocarbon liquids from controlled storage tanks to transport vehicles by using (a) submerged fill and (b) a vapor collection and return system and/or air pollution control equipment.

Owners or operators of class II disposal well facilities with VOC emissions from hydrocarbon liquids loadout to transport vehicles greater than or equal to two (2) tons uncontrolled actual emissions per year on a rolling 12-month basis must control emissions from the loadout of hydrocarbon liquids from storage tanks to transport vehicles by using (a) submerged fill and (b) a vapor collection and return system and/or air pollution control equipment.

- II.C.5.a.(i) Compliance with Section II.C.5. must be achieved in accordance with the following schedule
- II.C.5.a.(i)(A) Facilities constructed or modified on or after May 1, 2020, must be in compliance by commencement of operation.
 - II.C.5.a.(i)(B) Facilities constructed before May 1, 2020, must be in compliance by May 1, 2021.
 - II.C.5.a.(i)(C) Class II disposal well facilities constructed or modified on or after January 1, 2021, must be in compliance by commencement of operation.
 - II.C.5.a.(i)(D) Class II disposal well facilities constructed before January 1, 2021, must be in compliance by May 1, 2021.
 - II.C.5.a.(i)(E) Facilities not subject to Sections II.C.5.a.(i)(A) or II.C.5.a.(i)(B) that exceed the hydrocarbon liquids loadout to transport vehicles throughput of greater than or equal to 5,000 barrels per year on a rolling 12-month basis must control emissions from loadout upon exceeding the loadout threshold.
 - II.C.5.a.(i)(F) Facilities not subject to Sections II.C.5.a.(i)(C) or II.C.5.a.(i)(D) that exceed the hydrocarbon liquids loadout to transport vehicles emissions threshold of greater than or equal to two (2) tons uncontrolled actual VOC emissions per year on a rolling 12-month basis must control emissions from loadout within sixty (60) days of the first day of the month after which loadout emissions exceeded the loadout threshold.
- II.C.5.a.(ii) Storage tanks must operate without venting at all times during loadout.
- II.C.5.a.(iii) The owner or operator must, as applicable:

- II.C.5.a.(iii)(A) Install and operate the vapor collection and return equipment to collect vapors during the loadout of hydrocarbon liquids to tank compartments of outbound transport vehicles and to route the vapors to the storage tank or air pollution control equipment.
- II.C.5.a.(iii)(B) Include devices to prevent the release of vapor from vapor recovery hoses not in use.
- II.C.5.a.(iii)(C) Use operating procedures to ensure that hydrocarbon liquids cannot be transferred to transport vehicles unless the vapor collection and return system is in use.
- II.C.5.a.(iii)(D) Operate all recovery and disposal equipment at a back-pressure less than the pressure relief valve setting of transport vehicles.
- II.C.5.a.(iii)(E) The owner or operator must inspect onsite loading equipment to ensure that hoses, couplings, and valves are maintained to prevent dripping, leaking, or other liquid or vapor loss during loadout. These inspections must occur at least monthly, unless loadout occurs less frequently, then as often as loadout is occurring,
- II.C.5.a.(iv) Loadout observations and operator training
 - II.C.5.a.(iv)(A) The owner or operator must observe loadout to confirm that all storage tanks operate without venting when loadout operations are active. These inspections must occur at least monthly, unless loadout occurs less frequently, then as often as loadout is occurring,
 - II.C.5.a.(iv)(B) If observation of loadout is not feasible, the owner or operator must document the annual loadout frequency and the reason why observation is not feasible and inspect the facility within 24 hours after loadout to confirm that all storage tank thief hatches (or other access point to the tank) are closed and latched.
 - II.C.5.a.(iv)(C) The owner or operator must install signage at or near the loadout control system that indicates which loadout control method(s) is used and the appropriate and necessary operating procedures for that system.
 - II.C.5.a.(iv)(D) The owner or operator must develop and implement an annual training program for employees and/or third parties conducting loadout activities subject to Section II.C.5. that includes, at a minimum, operating procedures for each type of loadout control system.
- II.C.5.a.(v) Owners or operators must retain records for at least two (2) years and make such records available to the Division upon request.

- II.C.5.a.(v)(A) Records of the annual facility hydrocarbon liquids loadout to transport vehicles throughout.
- II.C.5.a.(v)(B) Inspections, including a description of any problems found and their resolution, required under Sections II.C.5.a.(iii) and II.C.5.a.(iv) must be documented in a log.
- II.C.5.a.(v)(C) Records of the infeasibility of observation of loadout.
- II.C.5.a.(v)(D) Records of the frequency of loadout.
- II.C.5.a.(v)(E) Records of the annual training program, including the date and names of persons trained.
- II.C.5.a.(v)(F) Records of class II disposal well facility VOC emissions from hydrocarbon liquids loadout to transport vehicles on a rolling 12-month basis.
- II.C.5.a.(vi) Air pollution control equipment used to comply with this Section II.C.5. must comply with Section II.B., be inspected in accordance with Sections II.C.1.d.(ii) through (v), and achieve a hydrocarbon control efficiency of 95%.

II.D. (State Only) Emission reductions from glycol natural gas dehydrators

- II.D.1. Beginning May 1, 2008, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, or gas-processing plant subject to control requirements pursuant to Section II.D.2., shall reduce uncontrolled actual emissions of volatile organic compounds by at least 90 percent through the use of a condenser or air pollution control equipment.
- II.D.2. The control requirement in Section II.D.1. apply where:
 - II.D.2.a. Actual uncontrolled emissions of volatile organic compounds from the glycol natural gas dehydrator are equal to or greater than two tons per year; and
 - II.D.2.b. The sum of actual uncontrolled emissions of volatile organic compounds from any single glycol natural gas dehydrator or grouping of glycol natural gas dehydrators at a single stationary source is equal to or greater than 15 tons per year. To determine if a grouping of dehydrators meets or exceeds the 15 tons per year threshold, sum the total actual uncontrolled emissions of volatile organic compounds from all individual dehydrators at the stationary source, including those with emissions less than two tons per year.
- II.D.3. Beginning May 1, 2015, still vents and vents from any flash separator or flash tank on a glycol natural gas dehydrator located at an oil and gas exploration and production operation, natural gas compressor station, or gas-processing plant subject to control requirements pursuant to Section II.D.4., shall reduce uncontrolled actual emissions of hydrocarbons by at least 95 percent on a rolling twelve-month basis through the use of a condenser or air pollution control equipment. If a combustion device is used, it shall have a design destruction efficiency of at least 98% for hydrocarbons, except where:
 - II.D.3.a. The combustion device has been authorized by permit prior to May 1, 2014; and

II.D.3.b. A building unit or designated outside activity area is not located within 1,320 feet of the facility at which the natural gas glycol dehydrator is located.

II.D.4. The control requirement in Section II.D.3. apply where:

II.D.4.a. Uncontrolled actual emissions of VOCs from a glycol natural gas dehydrator constructed on or after May 1, 2015, are equal to or greater than two (2) tons per year. Such glycol natural gas dehydrators must be in compliance with Section II.D.3. by the date that the glycol natural gas dehydrator commences operation.

II.D.4.b. Uncontrolled actual emissions of VOCs from a single glycol natural gas dehydrator constructed before May 1, 2015, are equal to or greater than six (6) tons per year, or two (2) tons per year if the glycol natural gas dehydrator is located within 1,320 feet of a building unit or designated outside activity area.

II.D.4.c. For purposes of Sections II.D.3. and II.D.4.:

II.D.4.c.(i) Building Unit means a residential building unit, and every five thousand (5,000) square feet of building floor area in commercial facilities or every fifteen thousand (15,000) square feet of building floor area in warehouses that are operating and normally occupied during working hours.

II.D.4.c.(ii) A Designated Outside Activity Area means an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of public assembly owned or operated by a local government, which the local government had established as a designated outside activity area by the COGCC; or an outdoor venue or recreation area where ingress to or egress from could be impeded in the event of an emergency condition at an oil and gas location less than three hundred and fifty (350) feet from the venue due to the configuration of the venue and the number of persons known or expected to simultaneously occupy the venue on a regular basis.

II.E. (State Only) Leak detection and repair program for well production facilities and natural gas compressor stations

II.E.1. The following provisions of Section II.E. apply in lieu of any directed inspection and maintenance program requirements established pursuant to Regulation Number 3, Part B, Section III.D.2.

II.E.2. Owners or operators of well production facilities or natural gas compressor stations that monitor components as part of Section II.E. may estimate uncontrolled actual emissions from components for the purpose of evaluating the applicability of component fugitive emissions to Regulation Number 3 by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017).

II.E.3. Beginning January 1, 2015, owners or operators of natural gas compressor stations must inspect components for leaks using an approved instrument monitoring method, in accordance with the following schedule

II.E.3.a. Approved instrument monitoring method inspections must begin within ninety (90) days after January 1, 2015, or the date the natural gas compressor station commences operation if such date is after January 1, 2015, for natural gas compressor stations with fugitive VOC emissions greater than zero (0) but less than or equal to fifty (50) tons per year, based on a rolling twelve-month total.

II.E.3.a.(i) Annual approved instrument monitoring method inspections at natural gas compressor stations with fugitive VOC emissions greater than zero (0) but less than or equal to twelve (12) tons per year, based on a rolling twelve-month total, must begin within ninety (90) days after January 1, 2015, or the date the natural gas compressor station commences operation if such date is after January 1, 2015. Annual inspections must be conducted through calendar year 2019.

II.E.3.a.(ii) Beginning calendar year 2020, owners or operators of natural gas compressor stations with fugitive VOC emissions greater than zero (0) but less than or equal to twelve (12) tons per year, based on a rolling twelve-month total, must conduct semi-annual approved instrument monitoring method inspections.

II.E.3.b. Approved instrument monitoring method inspections must begin within thirty (30) days after January 1, 2015, or the date the natural gas compressor station commences operation if such date is after January 1, 2015, for natural gas compressor stations with fugitive VOC emissions greater than fifty (50) tons per year.

II.E.3.c. Following the first approved instrument monitoring method inspection, owners or operators must continue conducting approved instrument monitoring method inspections in accordance with the Inspection Frequency in Table 2.

II.E.3.d. For purposes of Section II.E.3., fugitive emissions must be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), or other Division approved method.

Table 2 – Natural Gas Compressor Station Component Inspections	
Fugitive VOC Emissions (rolling twelve-month tpy)	Inspection Frequency
> 0 and ≤ 12	Semi-annually
> 12 and ≤ 50	Quarterly
> 50	Monthly

II.E.4. Requirements for well production facilities

- II.E.4.a. Owners or operators of well production facilities constructed on or after October 15, 2014, must identify leaks from components using an approved instrument monitoring method no sooner than fifteen (15) days and no later than thirty (30) days after the facility commences operation. This initial test constitutes the first, or only for facilities subject to a one time approved instrument monitoring method inspection, of the periodic approved instrument monitoring method inspections. Thereafter, approved instrument monitoring method and AVO inspections must be conducted in accordance with the Inspection Frequencies in Table 3.
- II.E.4.b. Owners or operators of well production facilities constructed before October 15, 2014, must identify leaks from components using an approved instrument monitoring method within ninety (90) days of the Phase-In Schedule in Table 3; within thirty (30) days for well production facilities subject to monthly approved instrument monitoring method inspections; or by January 1, 2016, for well production facilities subject to a one time approved instrument monitoring method inspection. Thereafter, approved instrument monitoring method and AVO inspections must be conducted in accordance with the inspection frequencies in Table 3.
- II.E.4.c. Beginning calendar year 2020, owners or operators of well production facilities with estimated uncontrolled actual VOC emissions greater than or equal to two (2) but less than or equal to twelve (12) tons per year as calculated in accordance with Section II.E.4.e., based on a rolling twelve-month total, must inspect components for leaks using an approved instrument monitoring method at least semi-annually.
- II.E.4.d. Beginning calendar year 2020, owners or operators of well production facilities with estimated uncontrolled actual VOC emissions greater than or equal to two (2) tons per year as calculated in accordance with Section II.E.4.e., based on a rolling twelve-month total, and located within 1,000 feet of an occupied area must inspect components for leaks using an approved instrument monitoring method in accordance with the inspection frequency in Table 3.
- II.E.4.e. The estimated uncontrolled actual VOC emissions from the highest emitting storage tank at the well production facility determines the frequency at which inspections must be performed. If no storage tanks storing oil or condensate are located at the well production facility, owners or operators must rely on the facility emissions (controlled actual VOC emissions from all permanent equipment, including emissions from components determined by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates).

Table 3 – Well Production Facility Component Inspections				
Thresholds (per II.E.4.d.)				
Well production facilities without storage tanks (rolling twelve-month tpy)	Well production facilities with storage tanks (rolling twelve-month tpy)	Approved Instrument Monitoring Method Inspection Frequency	AVO Inspection Frequency	Phase-In Schedule
> 0 and < 2	> 0 and < 2	One time	Monthly	January 1, 2016
≥ 2 and ≤ 12	≥ 2 and ≤ 12	Semi-annually	Monthly	* begins in 2020
> 2 and < 12, located within 1,000 feet of an occupied area	> 2 and < 12, located within 1,000 feet of an occupied area	Quarterly	Monthly	* begins in 2020
> 12 and ≤ 20	> 12 and ≤ 50	Quarterly	Monthly	January 1, 2015
> 12, located within 1,000 feet of an occupied area	> 12, located within 1,000 feet of an occupied area	Monthly		* begins in 2020
> 20	> 50	Monthly		January 1, 2015

II.E.5. If a component is unsafe, difficult, or inaccessible to monitor, the owner or operator is not required to monitor the component until it becomes feasible to do so.

II.E.5.a. Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two (2) meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

II.E.5.b. Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

II.E.5.c. Inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

II.E.6. Leaks requiring repair: Leaks must be identified utilizing the methods listed in Section II.E.6. Only leaks from components exceeding the thresholds in Section II.E.6. require repair under Section II.E.7.

- II.E.6.a. For EPA Method 21 monitoring, at facilities constructed before May 1, 2014, repair is required for leaks with any concentration of hydrocarbon above 2,000 parts per million (ppm) not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation, except for well production facilities where a leak is defined as any concentration of hydrocarbon above 500 ppm not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.
- II.E.6.b. For EPA Method 21 monitoring, at facilities constructed on or after May 1, 2014, repair is required for leaks with any concentration of hydrocarbon above 500 ppm not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.
- II.E.6.c. For infra-red camera and AVO monitoring, repair is required for leaks with any detectable emissions not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.
- II.E.6.d. For other Division approved instrument monitoring methods or programs, leak identification requiring repair will be established as set forth in the Division's approval.
- II.E.6.e. Except as provided in Section II.E.6.f., for leaks identified using an approved non-quantitative instrument monitoring method or AVO, owners or operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section II.E.7.a. or conducting follow-up monitoring using EPA Method 21 within five (5) working days of the leak detection. If the follow-up EPA Method 21 monitoring shows that the emission is a leak requiring repair as set forth in Section II.E.6., the leak must be repaired in accordance with Section II.E.7.a. and remonitored in accordance with Section II.E.7.c.
- II.E.6.f. Beginning on March 1, 2021, for leaks identified using an approved non-quantitative instrument monitoring method or AVO at a well production facility located within 1,000 feet of an occupied area, owners or operators have the option of either repairing the leak in accordance with the repair schedule set forth in Section II.E.7.b. or conducting follow-up monitoring using EPA Method 21 within five (5) working days of the leak detection. If the follow-up EPA Method 21 monitoring shows that the emission is a leak requiring repair as set forth in Sections II.E.6.a. through II.E.6.d., the leak must be repaired as follows and remonitored in accordance with Section II.E.7.c.
- II.E.6.f.(i) If EPA Method 21 indicates a leak greater than 500 ppm and less than 10,000 ppm hydrocarbons, the leak must be repaired in accordance with Section II.E.7.a.
- II.E.6.f.(ii) If EPA Method 21 is not performed or indicates a leak greater than or equal to 10,000 ppm hydrocarbons, the leak must be repaired in accordance with Section II.E.7.b

II.E.7. Repair and remonitoring

II.E.7.a. Except as provided in Section II.E.7.b., the first attempt to repair a leak must be made no later than five (5) working days after discovery and repair of a leak discovered on or after January 1, 2018, completed no later than thirty (30) working days after discovery, unless parts are unavailable, the equipment requires shutdown to complete repair, or other good cause exists.

II.E.7.a.(i) If parts are unavailable, they must be ordered promptly and the repair must be made within fifteen (15) working days of receipt of the parts.

II.E.7.a.(ii) If shutdown is required, a repair attempt must be made during the next scheduled shutdown and final repair completed within two (2) years after discovery.

II.E.7.a.(iii) If delay is attributable to other good cause, repairs must be completed within fifteen (15) working days after the cause of delay ceases to exist.

II.E.7.b. For leaks requiring repair pursuant to Section II.E.6.f., the first attempt to repair must be made as soon as practicable but no later than five (5) working days after discovery and completed within five (5) working days after discovery. If repair is not completed within five (5) working days after discovery, the owner or operator must use other means to stop the leak including, but not limited to, isolating the component or shutting in the well, unless such other means will cause greater emissions.

II.E.7.b.(i) If the owner or operator cannot repair or stop the leak within five (5) working days after discovery, the owner or operator must notify the local government with jurisdiction over the location and the Division as soon as possible, but no later than seven (7) working days after the leak is discovered. The notice must include

II.E.7.b.(i)(A) Identification of the facility, the leaking component, and contact information of the owner or operator representative;

II.E.7.b.(i)(B) The concentration of hydrocarbons using EPA Method 21, if available;

II.E.7.b.(i)(C) Instructions to access the infrared camera video footage of the leak, if available;

II.E.7.b.(i)(D) The approximate distance of the facility to the closest occupied area that is not an outdoor area;

II.E.7.b.(i)(E) The basis for the delay of repair and justification for not isolating the component or shutting in the well; and

II.E.7.b.(i)(F) The estimated date of repair.

II.E.7.c. Within fifteen (15) working days of completion of a repair, the leak must be remonitored using an approved instrument monitoring method to verify that the repair was effective.

II.E.7.d. Leaks discovered pursuant to the leak detection methods of Section II.E.6. are not subject to enforcement by the Division unless the owner or operator fails to perform the required repairs in accordance with Section II.E.7. or keep required records in accordance with Section II.E.8.

II.E.8. Recordkeeping: The owner or operator of each facility subject to the leak detection and repair requirements in Section II.E. must maintain the following records for a period of two (2) years and make them available to the Division upon request.

II.E.8.a. Documentation of the initial approved instrument monitoring method inspection for new well production facilities;

II.E.8.b. The date, facility name, and facility AIRS ID or facility location if the facility does not have an AIRS ID for each inspection;

II.E.8.c. A list of the leaking components requiring repair and the monitoring method(s) used to determine the presence of the leak;

II.E.8.d. The date and result of any EPA Method 21 monitoring relied upon to demonstrate a leak is not subject to Section II.E.7.b.;

II.E.8.e. The date of first attempt to repair the leak and, if necessary, any additional attempt to repair the leak;

II.E.8.f. The date the leak was repaired and for leaks discovered and repaired on or after January 1, 2018, the type of repair method applied;

II.E.8.g. Documentation of actions taken pursuant to Section II.E.7.b. to stop a leak that was not repaired within five (5) working days after discovery or documentation that such actions would cause greater emissions;

II.E.8.h. Copies of all notices submitted pursuant to Section II.E.7.b.(i) and the infrared camera video footage of leaks that required notice pursuant to Section II.E.7.b.(i);

II.E.8.i. The delayed repair list, including the basis for placing leaks on the list;

II.E.8.i.(i) For leaks discovered on or after January 1, 2018, the delayed repair list must include the date and duration of any period where the repair of a leak was delayed due to unavailable parts, required shutdown, or delay for other good cause, the basis for the delay, and the schedule for repairing the leak. Delay of repair beyond thirty (30) days after initial discovery due to unavailable parts must be reviewed, and a record kept of that review, by a representative of the owner or operator with responsibility for leak detection and repair compliance functions. This review will not be made by the individual making the initial determination to place a part on the delayed repair list.

II.E.8.i.(ii) For leaks discovered after March 1, 2021, that require repair pursuant to Section II.E.7.b., the delayed repair list must include the date and duration of leaks for which repairs were not completed within five (5) working days after discovery, and the schedule for repairing the leak.

II.E.8.j. The date the leak was remonitored and the results of the remonitoring;

- II.E.8.k. A list of components that are designated as unsafe, difficult, or inaccessible to monitor, as described in Section II.E.5., an explanation stating why the component is so designated, and the schedule for monitoring such component(s); and
 - II.E.8.l. Documentation of the owner or operator's proximity analysis, if applicable, including the date of the initial and any subsequent analysis and a description of the methodology used for the analysis.
- II.E.9. Reporting. The owner or operator of each facility subject to the leak detection and repair requirements in Section II.E. must submit a single annual report using the Division-approved format on or before May 31st of each year (beginning May 31st, 2019) that includes, at a minimum, the following information regarding leak detection and repair activities at their subject facilities conducted the previous calendar year:
- II.E.9.a. The total number of well production facilities and total number of natural gas compressor stations inspected;
 - II.E.9.b. The total number of inspections performed per inspection frequency tier of well production facilities, including the number of facilities inspected in accordance with Section II.E.4.d., and inspection frequency tier of natural gas compressor stations;
 - II.E.9.c. The total number of identified leaks requiring repair, broken out by component type, monitoring method, and inspection frequency tier of well production facilities, as reported in Section II.E.9.b., or inspection frequency tier of natural gas compressor stations;
 - II.E.9.d. The total number of leaks repaired for each inspection frequency tier of well production facilities, as reported in Section II.E.9.b., or inspection frequency tier of natural gas compressor stations;
 - II.E.9.e. The total number of leaks on the delayed repair list as of December 31st broken out by component type, inspection frequency tier of well production facilities, as reported in Section II.E.9.b., or inspection frequency tier of natural gas compressor stations, and the basis for each delay of repair. This total does not include leaks that have been stopped through other means, as specified in Section II.E.7.b.;
 - II.E.9.f. The record of all reviews conducted for delayed repairs due to unavailable parts extending beyond 30 days for the previous calendar year; and
 - II.E.9.g. Each report must be accompanied by a certification by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete
- II.F. Control of emissions from well production facilities

Well Operation and Maintenance: On or after August 1, 2014, gas coming off a separator, produced during normal operation from any newly constructed, hydraulically fractured, or recompleted oil and gas well, must either be routed to a gas gathering line or controlled from commencement of operation by air pollution control equipment that achieves an average hydrocarbon control efficiency of 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons.

II.G. (State Only) Emissions during downhole well maintenance, well liquids unloading events, and well plugging

II.G.1. Beginning May 1, 2014, owners or operators must use best management practices to minimize hydrocarbon emissions and the need for emissions from the well associated with downhole well maintenance, well liquids unloading, and well plugging (beginning January 31, 2020), unless emitting is necessary for safety.

II.G.1.a. During liquids unloading events, any means of creating differential pressure must first be used to attempt to unload the liquids from the well without emitting. If these methods are not successful in unloading the liquids from the well, the well may emit in order to create the necessary differential pressure to bring the liquids to the surface.

II.G.1.b. The owner or operator must be present on-site during any planned downhole well maintenance, well liquids unloading, or well plugging event and must ensure that any emissions from the well associated with the event are limited to the maximum extent practicable.

II.G.2. Recordkeeping

II.G.2.a. Through January 31, 2020, the owner or operator must keep records of the cause, date, time, and duration of venting events under Section II.G. Records must be kept for two (2) years and made available to the Division upon request.

II.G.2.b. Beginning January 31, 2020, or the date specified in Section II.G.2.b.(iii), the owner or operator must keep the following records for two (2) years and make records available to the Division upon request.

II.G.2.b.(i) The cause of emissions (i.e., downhole well maintenance, well liquids unloading, well plugging), date, time, and duration of emissions under Section II.G.

II.G.2.b.(ii) The best management practices used to minimize hydrocarbon emissions or the safety needs that prevented the use of best management practices.

II.G.2.b.(iii) Beginning July 1, 2020, the emissions associated with well liquids unloading, downhole well maintenance, and well plugging.

II.G.3. Reporting

II.G.3.a. The owner or operator must submit a single annual report using a Division-approved format on or before June 30th of each year (beginning June 30th, 2021) that includes the following information regarding each downhole well maintenance, well liquids unloading, and well plugging event conducted the previous calendar year that resulted in emissions.

II.G.3.a.(i) The API number of the well and the AIRS number of any associated storage tanks.

II.G.3.a.(ii) Whether the emissions occurred due to downhole well maintenance, well liquids unloading, or well plugging.

- II.G.3.a.(iii) The date, time, and duration of the downhole well maintenance, well liquids unloading, or well plugging event.
- II.G.3.a.(iv) The best management practices used to minimize emissions.
- II.G.3.a.(v) Safety needs that prevented the use of best management practices to minimize emissions, if applicable.
- II.G.3.a.(vi) An estimate of the volume of natural gas, VOC, NOx, N2), CO2, CO, ethane, and methane emitted from the well associated with well liquid unloading activities, downhole well maintenance, and well plugging event and the emission factor or calculation methodology used to determine the volume of natural gas and emissions.

III. Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations

III.A. Applicability

This section applies to pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations and natural gas compressor stations).

III.B. Definitions

- III.B.1. "Affected Operations" means pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations and natural gas compressor stations).
- III.B.2. "Continuous Bleed" means a continuous bleed rate of natural gas from a pneumatic controller that is designed to bleed natural gas continuously.
- III.B.3. "Custody Transfer" means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.
- III.B.4. (State Only) "Enhanced Response" means to return a pneumatic controller to proper operation and includes but is not limited to, cleaning, adjusting, and repairing leaking gaskets, and seals; tuning to operate over a broader range of proportional band; and eliminating unnecessary valve positioners.
- III.B.5. "High-Bleed Pneumatic Controller" means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.
- III.B.6. (State Only) "Intermittent pneumatic controller" means a pneumatic controller that is not designed to have a continuous bleed rate, but is designed to only release natural gas to the atmosphere as part of the actuation cycle.
- III.B.7. "Low-Bleed Pneumatic controller" means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.

- III.B.8. "Natural Gas Processing Plant" means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.
- III.B.9. "No-Bleed Pneumatic Controller" means any pneumatic controller that is not using hydrocarbon gas as the valve's actuating gas.
- III.B.10. (State Only) "Non-emitting Controller" means a device that monitors a process parameter such as liquid level, pressure or temperature and sends a signal to a control valve in order to control the process parameter and does not emit natural gas to the atmosphere. Examples of non-emitting controllers include but are not limited to: no-bleed pneumatic controllers, electric controllers, mechanical controllers and routed pneumatic controllers.
- III.B.11. "Pneumatic Controller" means a device that monitors a process parameter such as liquid level, pressure, or temperature and uses pressurized gas (which may be released to the atmosphere during normal operation) to send a signal to a control valve in order to control the process parameter. Controllers that do not utilize pressurized gas are not pneumatic controllers.
- III.B.12. (State Only) "Routed Pneumatic Controller" means a pneumatic controller that releases natural gas to a process, sales line or to a combustion device instead of directly to the atmosphere.
- III.B.13. "Self-contained Pneumatic Controller" means a pneumatic controller that releases gas to a process or sales line instead of to the atmosphere.
- III.B.14. (State Only) "Wellhead" means the piping, casing, tubing and connected valves supporting or controlling the operation of an oil and/or natural gas well. The wellhead does not include other process equipment at the wellhead site.

III.C. Emission Reduction Requirements

Owners and operators of affected operations shall reduce emissions of volatile organic compounds from pneumatic controllers associated with affected operations as follows:

- III.C.1. Continuous bleed, natural gas-driven pneumatic controllers in the 8-Hour Ozone Control Area and located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline:
- III.C.1.a. All pneumatic controllers placed in service on or after February 1, 2009, must emit natural gas emissions in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section III.C.1.c.
 - III.C.1.b. All high-bleed pneumatic controllers in service prior to February 1, 2009 shall be replaced or retrofit such that natural gas emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, by May 1, 2009, unless allowed pursuant to Section III.C.1.c.
 - III.C.1.c. All high-bleed pneumatic controllers that remain in service due to safety and/or process purposes must comply with Sections III.D. and III.E.
- III.C.1.c.(i) For high-bleed pneumatic controllers in service prior to February 1, 2009, the owner/operator must submit justification for high-

bleed pneumatic controllers to remain in service due to safety and /or process purposes by March 1, 2009.

- III.C.1.c.(ii) For high-bleed pneumatic controllers placed in service on or after February 1, 2009, the owner/operator must submit justification for high-bleed pneumatic controllers to be installed due to safety and /or process purposes thirty (30) days prior to installation.

III.C.2. Continuous bleed, natural gas-driven pneumatic controllers in the 8-Hour Ozone Control Area and located at a natural gas processing plant:

- III.C.2.a. All pneumatic controllers placed in service on or after January 1, 2018, must have a natural gas bleed rate of zero, unless allowed pursuant to Section III.C.2.c.
- III.C.2.b. All pneumatic controllers with a bleed rate greater than zero in service prior to January 1, 2018, must be replaced or retrofit such that the pneumatic controller has a natural gas bleed rate of zero by May 1, 2018, unless allowed pursuant to Section III.C.2.c.
- III.C.2.c. All pneumatic controllers with a natural gas bleed rate greater than zero that remain in service due to safety and/or process purposes must comply with Sections III.D. and III.E.
 - III.C.2.c.(i) For pneumatic controllers with a natural gas bleed rate greater than zero in service prior to January 1, 2018, the owner or operator must submit justification for pneumatic controllers to remain in service due to safety and /or process purposes by May 1, 2018.
 - III.C.2.c.(ii) For pneumatic controllers with a natural gas bleed rate greater than zero placed in service on or after January 1, 2018, the owner or operator must submit justification for pneumatic controllers to be installed due to safety and /or process purposes thirty (30) days prior to installation.

III.C.3. (State Only) Statewide:

- III.C.3.a. Owners or operators of all pneumatic controllers placed in service on or after May 1, 2014 and before May 1, 2021, must:
 - III.C.3.a.(i) Utilize no-bleed pneumatic controllers where on-site electrical grid power is being used and use of a no-bleed pneumatic controller is technically and economically feasible.
 - III.C.3.a.(ii) If on-site electrical grid power is not being used or a no-bleed pneumatic controller is not technically and economically feasible, utilize pneumatic controllers that emit natural gas emissions in an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section III.C.3.c.
 - III.C.3.a.(iii) For purposes of Section III.C.3.a.(ii), instead of a low-bleed pneumatic controller, owners or operators may utilize a natural gas-driven intermittent pneumatic controller.

- III.C.3.a.(iv) Utilizing self-contained pneumatic controllers satisfies Section III.C.3.a.(i).
- III.C.3.b. All high-bleed pneumatic controllers in service prior to May 1, 2014, must be replaced or retrofitted by May 1, 2015, such that natural gas emissions are reduced to an amount equal to or less than a low-bleed pneumatic controller, unless allowed pursuant to Section III.C.3.c.
- III.C.3.c. All high-bleed pneumatic controllers that must remain in service due to safety and/or process purposes must comply with Sections III.D. and III.E.
 - III.C.3.c.(i) For high-bleed pneumatic controllers in service prior to May 1, 2014, the owner/operator must submit justification for high-bleed pneumatic controllers to remain in service due to safety and/or process purposes by March 1, 2015.
 - III.C.3.c.(ii) For high-bleed pneumatic controllers placed in service on or after May 1, 2014, the owner/operator must submit justification for high-bleed pneumatic controllers to be installed due to safety and/or process purposes thirty (30) days prior to installation.
- III.C.4. (State Only) Non-Emitting Controller Requirements for Well Production Facilities and Natural Gas Compressor Stations
 - III.C.4.a. Except as provided in Section III.C.4.e.(i), the following facilities must use only non-emitting controllers:
 - III.C.4.a.(i) Well production facilities that commence operations on or after May 1, 2021;
 - III.C.4.a.(ii) Well production facilities that receive production from a well that first begins production or is recompleted or refractured on or after May 1, 2021; and
 - III.C.4.a.(iii) Natural gas compressor stations that commence operations or increase compression horsepower on or after May 1, 2021.
 - III.C.4.b. Each well production facility and natural gas compressor station with non-emitting controllers used to satisfy the requirements of Sections III.C.4.a.(i) through (iii) must contain on-site signage indicating that the facility utilizes non-emitting controllers to satisfy the requirements of this Section III.C.4. This Section III.C.4.b does not apply to operator's subject to Section III.C.4.d.(vi).
 - III.C.4.c. Company-Wide Non-Emitting Controller Program for Well Production Facilities That Commenced Operation Before May 1, 2021
 - III.C.4.c.(i) Except as provided for in Section III.C.4.c.(iv), owners or operators of well production facilities that commenced operation before May 1, 2021, must phase out pneumatic controllers that emit natural gas to the atmosphere in accordance with Table 1.

III.C.4.c.(ii) Except as provided for in Section III.C.4.c.(iv), owners or operators of well production facilities that commenced operations before May 1, 2021, must:

III.C.4.c.(ii)(A) Determine Historic Facility Production for each existing well production facility that commenced operation before May 1, 2021.

III.C.4.c.(ii)(A)(1) Historic Facility Production at each existing well production facility which first began production during 2018 or earlier must be based on total liquids production (summing total barrels of oil and water produced through the well production facility) for the calendar year 2019.

III.C.4.c.(ii)(A)(2) Notwithstanding Section III.C.4.c.(ii)(A)(1), for any well production facility to which a well first began production during 2019, 2020 or by May 1, 2021, historic facility production must be based on the production for the first twelve (12) months beginning with the date of first production of the latest well to begin production prior to May 1, 2021.

III.C.4.c.(ii)(A)(3) Notwithstanding Sections III.C.4.c.(ii)(A)(1) and (2), for any well production facility to which a well first began production during 2019, 2020, or by May 1, 2021, if twelve (12) months since date of first production of the latest well to begin production has not passed as of May 1, 2021, then the owner or operator must use an estimate of the anticipated yearly production for the facility based on industry accepted calculation methodologies.

III.C.4.c.(ii)(B) Calculate the Total Historic Production for the owner or operator by summing the Historic Facility Production for all existing well production facilities that commenced operation before May 1, 2021.

III.C.4.c.(ii)(C) Determine the percentage of total liquids production for each existing facility (the Facility Percent Production) by dividing the Historic Facility Production for that facility by the Total Historic Production.

III.C.4.c.(ii)(D) Determine the Historic Non-Emitting Facility Percent Production.

- III.C.4.c.(ii)(D)(1) If the well production facility, including all wellheads flowing to the well production facility, uses only non-emitting controllers, then the Facility Percent Production should be designated as Historic Non-Emitting Facility Percent Production.
- III.C.4.c.(ii)(D)(2) In making the determination in Section III.C.4.c.(ii)(D)(1), pneumatic controllers that meet the conditions in Section III.C.4.e.(i) need not be considered.
- III.C.4.c.(ii)(E) Determine the Total Historic Non-Emitting Facility Percent Production percentage by summing the Historic Non-Emitting Facility Percent Production for all well production facilities that commenced operation prior to May 1, 2021. The Total Historic Non-Emitting Facility Percent Production determines an owner or operators' May 1, 2022 and May 1, 2023 Additional Required Non-Emitting Facility Percent Production, as set forth in Table 1.
- III.C.4.c.(iii) Owners or operators must demonstrate compliance with Table 1's May 1, 2022 and May 1, 2023 Additional Required Non-Emitting Facility Percent Production through any combination of (1) retrofitting well production facilities to utilize non-emitting controllers or (2) plugging and abandoning an existing well production facility.
- III.C.4.c.(iv) An owner or operator that demonstrates that its total statewide oil and natural gas production averages 15 barrels of oil equivalent or less per day per well is not subject to the requirements of Sections III.C.4.c.(i) through (iii). To calculate average statewide oil and natural gas production per day per well, an owner or operator must sum all oil and natural gas production for calendar year 2019 in barrels of oil equivalent, divide by three hundred and sixty-five, and divide by the number of wells the owner or operator operated statewide that produced hydrocarbons in 2019.
- III.C.4.c.(v) If a well production facility for which production was included in a calculation of achieving a Total Required Non-Emitting Facility Percent Production target is sold or transferred prior to May 1, 2023 and the selling or transferring owner or operator plans to utilize the well production facility to show compliance with Table 1, the selling or transferring owner or operator (and the buyer or transferee, as applicable) must submit to the Division an acknowledgment or certification within 30 days following sale or transfer, in a form acceptable to the Division, identifying how the selling or transferring owner or operator will utilize the well production facility to show compliance with Table 1.
- In each submission of the updated Company-Wide Well Production Facility Natural Gas-Driven Pneumatic Controller

Compliance Plan, the owner or operator will provide the date (month and year) when a well production facility was transferred since the last submission and whether or not the well production facility contributed or will contribute towards achieving the Total Required Non-Emitting Facility Percent Production. An owner or operator that merges with or acquires an owner or operator with a Company-Wide Well Production Facility Natural Gas-Driven Pneumatic Controller Compliance Plan must comply, despite the resulting ownership or operatorship, with each Company-Wide Well Production Facility Natural Gas-Driven Pneumatic Controller Compliance Plan, as applicable, and as established on September 1, 2021.

- III.C.4.c.(vi) For each facility designated as contributing to Historic Non-Emitting Facility Percent Production, the owner or operator will place signage on-site by October 1, 2021 indicating that the facility utilizes non-emitting controllers to satisfy the requirements of this Section III.C.4.c.

TABLE 1*—Well Production Facilities					
Total Historic Non-Emitting Facility Percent Production	May 1, 2022 Additional Required Non-Emitting Facility Percent Production	May 1, 2022 Maximum Required Non-Emitting Facility Percent Production	May 1, 2023 Additional Required Non-Emitting Facility Percent Production	May 1, 2023 Maximum Required Non-Emitting Facility Percent Production	Total Additional Required Non-Emitting Facility Percent Production By May 1 2023
> 75 %	+5%	90%	+10%	96.5%	+15%
> 60-75 %	+5%	80%	+10%	90%	+15%
> 40-60 %	+10%	65%	+15%	75%	+25%
> 20-40 %	+15%	50%	+20%	65%	+35%
0-20 %	+15%	35%	+25%	55%	+40%

* Table 1 establishes minimum increases in the percentage of liquids produced (based on historic non-emitting controller use) from non-emitting facilities. Owners or operators do not need to go beyond the maximum required percentages set forth in Table 1, although they may choose to do so.

- III.C.4.d. Company-Wide Non-Emitting Controller Compliance Program for Natural Gas Compressor Stations that Commenced Operation Before May 1, 2021.

- III.C.4.d.(i) Owners or operators of natural gas compressor stations that commenced operation before May 1, 2021, must phase out pneumatic controllers that emit natural gas to the atmosphere in accordance with Table 2.
- III.C.4.d.(ii) Owners or operators of natural gas compressor stations that commenced operation before May 1, 2021, must:

- III.C.4.d.(ii)(A) Determine Total Controller Count for all controllers at all of the owner or operator's natural gas compressor stations that commenced operation before May 1, 2021. The Total Controller Count must include all pneumatic controllers and all non-emitting controllers, except that pneumatic controllers excluded under Sections III.C.4.e.(i)(A) through (C) are not included in the Total Controller Count.
- III.C.4.d.(ii)(B) Determine which controllers in the Total Controller Count are non-emitting and sum the total number of non-emitting controllers and designate those as Total Historic Non-Emitting Controllers.
- III.C.4.d.(ii)(C) Determine the Total Historic Non-Emitting Percent Controllers by dividing the Total Historic Non-Emitting Controller Count by the Total Controller Count.
- III.C.4.d.(iii) Owners or operators must demonstrate compliance with Table 2's May 1, 2022 and May 1, 2023 Additional Required Percentage of Non-Emitting Controllers through any combination of (1) retrofitting controllers at natural gas compressor stations to utilize non-emitting controllers or (2) permanently removing natural gas compressor stations from service.
- III.C.4.d.(iv) Pneumatic controllers that emit natural gas to atmosphere at natural gas compressor stations with non-emitting controllers must be tagged, which will indicate that the controller may emit natural gas. The tags must differentiate between pneumatic controllers that are exempt under Sections III.C.4.e.(i)(A) through (C) and pneumatic controllers that emit natural gas to the atmosphere under the company-wide plan. Tagging pursuant to this Section III.C.4.d.(iv) must occur by May 1, 2022.
- III.C.4.d.(v) If a natural gas compressor station for which the number of pneumatic controllers located at such compressor station was included in a calculation of achieving a Total Required Non-Emitting Percent Controllers target is sold or transferred prior to May 1, 2023 and the selling or transferring owner or operator plans to utilize the pneumatic controllers at that natural gas compressor station to show compliance with Table 2, the selling or transferring owner or operator (and the buyer or transferee, as applicable) must submit to the Division an acknowledgement or certification, within 30 days following sale or transfer, in a form acceptable to the Division, identifying how the selling or transferring owner or operator will utilize the pneumatic controllers at that natural gas compressor station to show compliance with Table 2.

In each submission of the updated Company-Wide Compressor Station Pneumatic Controller Compliance Plan, the owner or operator will provide the date (month and year) when the natural gas compressor station was transferred since the last submission and whether or not the compressor station contributed or will contribute towards achieving the Total Required Non-Emitting Percent Controllers. An owner or operator that merges with or acquires an owner or operator with a Company-Wide Compressor Station Pneumatic Controller Compliance Plan must comply, despite the resulting ownership or operatorship, with each Company-Wide Compressor Station Pneumatic Controller Compliance Plan, as applicable, and as established on September 1, 2021.

III.C.4.d.(vi) This section applies to owners or operators of natural gas compressor stations where all the owner or operator's active, operating natural gas compressor stations use only non-emitting controllers (except that pneumatic controllers that qualify for the exclusions set forth in Sections III.C.4.e.(i)(A) through (C) are not required to be non-emitting controllers).

III.C.4.d.(vi)(A) No later than September 1, 2021, such owners or operators may file a one-time notification with the Division in lieu of the requirements in Sections III.C.4.d.(i) through (iii) that:

III.C.4.d.(vi)(A)(1) Lists each active, operating natural gas compressor station (including AIRS identification numbers and facility names) and that includes a certification by the company representative that supervised the development and submission of the notification that, based on information and belief formed after reasonable inquiry, each of its active, operating natural gas compressor stations uses only non-emitting controllers (except that pneumatic controllers that qualify for the exclusions set forth in Sections III.C.4.e.(i)(A) through (C) are not required to be non-emitting controllers); and

III.C.4.d.(vi)(A)(2)

Lists each inactive, non-operating compressor station (including AIRS identification numbers and facility names) and that includes a certification by the company representative that supervised the development and submission of the notification that after May 1, 2021, such compressor stations have not and subsequently will not operate with pneumatic controllers that emit natural gas to the atmosphere, except pneumatic controllers that qualify for exclusions set forth in subject to Sections III.C.4.e.(i)(A) through (C).

III.C.4.d.(vi)(B) If applicable, the notifications submitted under this section must list any pneumatic controllers that qualify for exclusions pursuant to Sections III.C.4.e.(i)(A) through (C) and identify the specific exemption applicable to each such pneumatic controller. Operators must tag any controller qualifying for the exclusions in Sections III.C.4.e.(i)(A) through (C) by October 1, 2021.

III.C.4.d.(vi)(C) The owner or operator must maintain a copy of the one-time notification required by Section III.C.4.d.(vi)(A) for five years.

TABLE 2* – Natural Gas Compressor Stations					
Total Historic Percentage of Non-Emitting Controllers	May 1, 2022 Additional Required Percentage of Non-Emitting Controllers	May 1, 2022 Maximum Required Percentage of Non-Emitting Controllers	May 1, 2023 Additional Required Percentage of Non-Emitting Controllers	May 1, 2023 Maximum Required Percentage of Non-Emitting Controllers	Total Additional Required Percentage of Non-Emitting Controllers By May 1, 2023
> 75 %	+10%	90%	+15%	100%	+25%
>60-75 %	+10%	85%	+20%	92%	+30%
>40-60 %	+10%	70%	+25%	75%	+35%
>20-40 %	+15%	50%	+25%	65%	+40%
0-20 %	+20%	35%	+25%	60%	+45%

* Table 2 establishes minimum additional percentages of non-emitting controllers required by May 1, 2022 and May 1, 2023 based on a company's historic percentage of non-emitting controllers. Owners and operators need not go beyond the maximum required percentages specified in Table 2, although they may choose to do so.

III.C.4.e. Pneumatic Controllers That Emit Natural Gas to the Atmosphere Not Subject to Non-Emitting Controller Requirements for Well Production Facilities and Natural Gas Compressor Stations.

- III.C.4.e.(i) Pneumatic controllers that emit natural gas to the atmosphere meeting any of the following conditions are not subject to the requirements in Section III.C.4.a. and are not required to be retrofit in order to count the facility or controller as non-emitting for compliance with the company-wide plans under Sections III.C.4.c. and III.C.4.d.
- III.C.4.e.(i)(A) Pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas.
- III.C.4.e.(i)(A)(1) Owners or operators that seek to rely on this exemption for facilities listed in Sections III.C.4.a.(i) through (iii) must submit a justification for the safety or process purposes to the Division for approval forty-five (45) days prior to installation of emitting device or retrofit of the facility. If the Division does not respond to the justification within forty-five (45) days after submission of the justification, the justification will be deemed approved.
- III.C.4.e.(i)(A)(2) Owners or operators that seek to rely on this exemption to maintain emitting controllers at facilities that are retrofit to meet requirements of Section III.C.4.c.(i) must submit a justification for the safety or process purposes to the Division for approval forty-five (45) days prior to retrofit of the facility. If the Division does not respond to the justification within forty-five (45) days after submission of the justification, the justification will be deemed approved.
- III.C.4.e.(i)(B) Pneumatic controllers that emit natural gas located on temporary or portable equipment that is used for well abandonment activities or used prior to or through the end of flowback.
- III.C.4.e.(i)(C) Pneumatic controllers that emit natural gas located on temporary or portable equipment meeting the requirements of this Section III.C.4.e.(i)(C).

- III.C.4.e.(i)(C)(1) Upon notice to the Division on a form developed by the Division, pneumatic controllers that emit natural gas other than those covered by Section III.C.4.e.(i)(B) located on temporary or portable equipment that is in use and onsite for sixty (60) days or less. However, this exemption for temporary or portable equipment does not apply to pneumatic controllers that emit natural gas used on temporary or portable equipment to temporarily increase throughput capacity of a facility.
- III.C.4.e.(i)(C)(2) An owner or operator must obtain written approval from the Division for continued use beyond 60 days of pneumatic controllers that emit natural gas under Section III.C.4.e.(i)(C). The owner or operator must submit the request for an extension to the Division at least fourteen (14) days before the 60-day period expires. If the Division does not respond to the request before the 60-day period expires, the request will be deemed approved until such time as the Division may determine that the extension should be denied.
- III.C.4.e.(i)(C)(2)(a) To request such an exemption, the owner or operator must submit a plan for Division approval which (1) identifies the temporary or portable equipment and number and type of pneumatic controllers that emit natural gas, (2) identifies how long the owner or operator plans to keep the equipment on site, (3) explains the need for an extension, and (4) other information as reasonably required by the Division.
- III.C.4.e.(i)(C)(2)(b) In explaining the need for an extension, the operator must clearly identify the basis for extension; the anticipated schedule for use of the temporary or portable equipment; and the steps taken to minimize the length of the requested extension.

III.C.4.e.(i)(C)(3) The operator must inspect the pneumatic controllers using approved instrument monitoring method and AVO, consistent with Section II.E, at the same frequency as the associated well production facility or compressor station, and must comply with the repair, recordkeeping, and reporting provisions in Sections II.E.6 through 9.

III.C.4.e.(i)(D) Pneumatic controllers that emit natural gas to the atmosphere that are used as emergency shutdown devices and for artificial lift control located on a wellhead: (1) greater than one quarter mile from the associated production facilities for well production facilities that commenced operation on or after May 1, 2021; or (2) not located on the same surface disturbance as the associated production facilities for well production facilities that commenced operation before May 1, 2021.

III.C.4.e.(i)(D)(1) Owners or operators who seek to use a pneumatic controller at a qualifying wellhead at a facility listed in Sections III.C.4.a.(i) or (ii) that is not used as an emergency shutdown device or for artificial lift control must submit a justification for the use of such a pneumatic controller to the Division for approval forty-five (45) days prior to installation of the emitting device or retrofit of the facility. If the Division does not respond to the justification within forty-five (45) days after submission of the justification, the justification will be deemed approved.

III.C.4.e.(i)(D)(2) Owners or operators that seek to rely on this exemption to exclude emitting pneumatic controllers at a qualifying wellhead that are not used as an emergency shutdown device or for artificial lift control when determining their Total Historic Non-Emitting Facility Percent Production pursuant to Section III.C.4.c.(ii) must submit a justification to the Division for approval no later than July 1, 2021. If the Division does not respond to the justification by August 15, 2021, the justification will be deemed approved.

III.C.4.e.(i)(D)(3) Operators that utilize the exemption in Section III.C.4.e.(i)(D) must identify leaks from components using an approved instrument monitoring method and AVO, consistent with Section II.E, at the same frequency as the well production facility to which the well flows as set forth in Table 3 of Section II.E.4, or on a frequency no less than one time per year, whichever is greater, and must comply with the repair, recordkeeping, and reporting provisions in Sections II.E.6 through 9. For well production facilities that commenced operation before May 1, 2021 with wellheads utilizing this exemption, the requirement in this Section III.C.4.e.(i)(D)(3) must begin May 1, 2022.

III.C.4.e.(i)(D)(3)(a) An owner or operator that cannot reasonably access the wellhead site to conduct a monthly AIMM or AVO inspection due to circumstances beyond its control (including but not limited to the presence of crops, wildlife restrictions, or severe weather conditions) shall conduct an AVO or AIMM inspection, as applicable, within 14 days of the condition preventing inspection being resolved. Owners or operators that rely on this Section III.C.4.e.(i)(D)(3)(a) must maintain records pursuant to Section III.C.4.g.(vii) and report pursuant Section III.C.4.g.(viii).

III.C.4.e.(i)(D)(3)(b) Operators may use drone-mounted infra-red cameras that ensure line of sight and appropriate distance from the drone to all wellhead equipment and components to conduct the inspections required under Section III.C.4.e.(1)(D)(3). Operators must develop their own methodology before using OGI camera-equipped aerial drones and make that methodology available to the Division upon request.

- III.C.4.e.(i)(D)(4) If a wellhead has on-site electrical grid power to operate an electric controller, then operators may not utilize the exemption in Section III.C.4.e.(i)(D) for any pneumatic controller at the wellhead for which it is technically feasible to utilize an electric controller.
- III.C.4.e.(i)(D)(5) Operators may not utilize the exemption in Section III.C.4.e.(i)(D) where equipment with pneumatic controllers other than the wellhead is located at the wellhead site.
- III.C.4.e.(ii) By October 1, 2021, each pneumatic controller at a well production facility that emits natural gas pursuant to Sections III.C.4.e.(i)(A) through (D) must be tagged, which will indicate that the controller may emit natural gas.
- III.C.4.e.(iii) By October 1, 2021, each pneumatic controller at a natural gas compressor station that emits natural gas pursuant to Sections III.C.4.e.(i)(A) through (C) must be tagged, which will indicate that the controller may emit natural gas.
- III.C.4.f. Company-Wide Well Production Facility and Natural Gas Compressor Station Reporting Requirements.
- III.C.4.f.(i) Owners and operators of well production facilities subject to Sections III.C.4.c.(i) through (iii) must submit a Company-Wide Well Production Facility Pneumatic Controller Compliance Plan to the Division on the Division-approved form by September 1, 2021, and include all of the following elements:
- III.C.4.f.(i)(A) A list of existing well production facilities as of May 1, 2021, including AIRS identification numbers and facility names.
- III.C.4.f.(i)(B) The following for each well production facility:
- III.C.4.f.(i)(B)(1) Historic Facility Production.
- III.C.4.f.(i)(B)(2) Facility Percent Production.
- III.C.4.f.(i)(B)(3) Historic Non-Emitting Facility Percent Production.
- III.C.4.f.(i)(B)(4) The API number for each producing well included in the Total Historic Facility Production.
- III.C.4.f.(i)(C) The following company-wide information:
- III.C.4.f.(i)(C)(1) Total Historic Production.

- III.C.4.f.(i)(C)(2) Total Historic Non-Emitting Facility Percent Production, including a list of facilities already using non-emitting controllers as determined in Section III.C.4.c.(ii)(E).
- III.C.4.f.(i)(C)(3) Total Required Non-Emitting Facility Percent Production.
- III.C.4.f.(i)(D) An indication of which and in what year well production facilities are expected to be retrofit with non-emitting controllers, or plugged and abandoned, to meet the required Additional Non-Emitting Facility Percent Production for each year listed in Table 1.
- III.C.4.f.(ii) Owners or operators will submit an updated Company-Wide Facility Pneumatic Controller Compliance Plan by July 1 of each year listed in Table 1, unless the owner or operator has demonstrated compliance with the Total Required Non-Emitting Facility Percent Production in a previous year's plan. The updated plan will include all of the following elements:
- III.C.4.f.(ii)(A) All elements set forth in Sections III.C.4.f.(i)(A) through (C).
- III.C.4.f.(ii)(B) The date (month and year) that any well production facilities were retrofit or plugged and abandoned since the prior submission, which may vary from the information previously provided pursuant to Section III.C.4.f.(i)(D).
- III.C.4.f.(ii)(C) An update of information set forth in Section III.C.4.f.(i)(D) if the Total Required Non-Emitting Facility Percent Production required by Table 1 has not been met.
- III.C.4.f.(ii)(D) For each submission, the owner or operator must list each existing well production facility that is utilizing non-emitting controllers and provide a demonstration that the required Additional Non-Emitting Facility Percent Production for the relevant year has been met.
- III.C.4.f.(ii)(E) In the final year, the owner or operator must additionally provide a demonstration that the Total Required Non-Emitting Facility Percent Production has been met.
- III.C.4.f.(iii) Owners and operators of natural gas compressor stations subject to Sections III.C.4.d.(i) through (iii) must submit a Company-Wide Compressor Station Pneumatic Controller Compliance Plan to the Division on a Division-approved form by September 1, 2021, and include all of the following elements:
- III.C.4.f.(iii)(A) A listing of existing natural gas compressor stations as of May 1, 2021, including AIRS identification numbers and facility names.

III.C.4.f.(iii)(B) The following company-wide information:

III.C.4.f.(iii)(B)(1) Total Controller Count, including a list of each pneumatic controller and all non-emitting controllers, except that pneumatic controllers excluded under Sections III.C.4.e.(i)(A) through (C) are not included in the Total Controller Count.

III.C.4.f.(iii)(B)(2) Total Historic Non-Emitting Controllers, including an indication as to which controllers are already non-emitting.

III.C.4.f.(iii)(B)(3) Total Required Non-Emitting Facility Percent Controllers.

III.C.4.f.(iii)(C) An indication of which and in what year controllers are expected to be retrofit with non-emitting controllers or removed from service (as applicable) to meet the required Additional Non-Emitting Percent Controllers for each year listed in Table 2.

III.C.4.f.(iv) Owners or operators will submit an updated Company-Wide Compressor Station Pneumatic Controller Compliance Plan by July 1 of each year listed in Table 2, unless the owner or operator has demonstrated compliance with the Total Required Non-Emitting Percent Controllers in a previous year's plan. The updated plan will include all of the following elements:

III.C.4.f.(iv)(A) All elements set forth in Sections III.C.4.f.(iii)(A) through (B).

III.C.4.f.(iv)(B) The date (month and year) that any controllers at natural gas compressor stations were retrofit or removed from service since the prior submission, which may vary from the information previously provided pursuant to Section III.C.4.f.(iii)(C).

III.C.4.f.(iv)(C) The information set forth in Section III.C.4.f.(iii)(C) if the Total Required Non-Emitting Percent Controllers required by Table 2 has not been met.

III.C.4.f.(iv)(D) For each submission, the owner or operator must list total controllers and total non-emitting controllers at existing natural gas compressor stations and provide a demonstration that the required Additional Non-Emitting Percent Controllers for the relevant year has been met.

III.C.4.f.(iv)(E) In the final year, the owner or operator must additionally provide a demonstration that the Total Required Non-Emitting Percent Controller has been met.

- III.C.4.g. Recordkeeping and Reporting Requirements. The records in Sections III.C.4.g.(i) through (vii) must be kept for a period of five years and made available to the Division upon request.
- III.C.4.g.(i) Records of the date a well production facility completes retrofit or all wells flowing to the well production facility are plugged and abandoned, or the date natural gas compressor station pneumatic controllers were retrofit or is taken out of service.
 - III.C.4.g.(ii) If claiming an exemption under Sections III.C.4.e.(i)(A) – (D), records for each pneumatic controller demonstrating that the exemption applies.
 - III.C.4.g.(iii) Copies of the Company-Wide Well Production Facility Pneumatic Controller Compliance Plan and Company-Wide Compressor Station Pneumatic Controller Compliance Plans required to be submitted by Sections III.C.4.f.(i) – (iv).
 - III.C.4.g.(iv) For any owner or operator utilizing the provision in Section III.C.4.c.(iv), the records described in Section III.C.4.c.(iv) that demonstrate the owner or operator qualifies for that provision.
 - III.C.4.g.(v) For each pneumatic controller required to be tagged pursuant to Sections III.C.4.d.(iv), III.C.4.d.(vi)(B), III.C.4.e.(ii), or III.C.4.e.(iii), a list of each tagged pneumatic controller, equipment location, and its tag identification number.
 - III.C.4.g.(vi) Records required to be submitted to the Division pursuant to Sections III.C.4.c.(v) and III.C.4.d.(v).
 - III.C.4.g.(vii) Owners or operators that rely on Section III.C.4.e.(i)(D)(3)(a) must maintain: (1) the date of the AIMM or AVO inspection at the production facility to which the well flows, (2) the date of the AIMM or AVO inspection of the wellhead site once the conditions preventing inspection has been resolved, and (3) records demonstrating the circumstances that prevented the wellhead site from being inspected.
 - III.C.4.g.(viii) Owners or operators that rely on Section III.C.4.e.(i)(D)(3)(a) shall report annually by May 31 of each year, on a form approved by the Division, the number of wellhead sites for which the AIMM inspection was delayed pursuant to Section III.C.4.e.(i)(D)(3)(a), the number of wellhead sites for which the AVO inspection was delayed pursuant to Section III.C.4.e.(i)(D)(3)(a), and the total number of wellhead sites where inspections were delayed pursuant to Section III.C.4.e.(i)(D)(3)(a) for (1) 30 days or less, (2) greater than 30 days but less than or equal to 90 days, and (3) greater than 90 days.

III.D. Monitoring

This section applies to pneumatic controllers identified in Sections III.C.1.c. and III.C.2.c. (State Only: and in Section III.C.3.c.).

- III.D.1. In the 8-Hour Ozone Control Area and located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline:

III.D.1.a. Effective May 1, 2009, each high-bleed pneumatic controller must be physically tagged by the owner or operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner or operator.

III.D.1.b. Effective May 1, 2009, the owner or operator must inspect each high-bleed pneumatic controller on a monthly basis, perform necessary maintenance (such as cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band, eliminating unnecessary valve positioners), and maintain the pneumatic controller according to manufacturer specifications to ensure that the controller's natural gas emissions are minimized.

III.D.2. In the 8-Hour Ozone Control Area and located at a natural gas processing plant:

III.D.2.a. Effective May 1, 2018, each pneumatic controller with a natural gas bleed rate greater than zero must be physically tagged by the owner or operator identifying it with a unique pneumatic controller number that is assigned and maintained by the owner or operator.

III.D.2.b. Effective May 1, 2018, the owner or operator must inspect each pneumatic controller with a natural gas bleed rate greater than zero on a monthly basis, perform necessary maintenance (such as cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; eliminating unnecessary valve positioners), and maintain the pneumatic controller according to manufacturer specifications to ensure that the controller's natural gas emissions are minimized.

III.D.3. (State Only) Statewide:

III.D.3.a. Effective May 1, 2015, each high-bleed pneumatic controller must be physically tagged by the owner or operator identifying it with a unique high-bleed pneumatic controller number that is assigned and maintained by the owner or operator.

III.D.3.b. Effective May 1, 2015, the owner or operator must inspect each high-bleed pneumatic controller on a monthly basis, perform necessary maintenance (such as cleaning, tuning, and repairing leaking gaskets, tubing fittings, and seals; tuning to operate over a broader range of proportional band; eliminating unnecessary valve positioners), and maintain the pneumatic controller according to manufacturer specifications to ensure that the controller's natural gas emissions are minimized.

III.E. Recordkeeping

III.E.1. In the 8-Hour Ozone Control Area:

III.E.1.a. Continuous bleed, natural gas-driven pneumatic controllers located from the wellhead to the natural gas processing plant or point of custody transfer to an oil pipeline:

- III.E.1.a.(i) By January 1, 2019, owners or operators must compile an estimate of the total number of continuous bleed, natural gas-driven pneumatic controllers in service prior to January 1, 2018, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is less than or equal to 6 standard cubic feet of gas per hour.
- III.E.1.a.(ii) Beginning January 1, 2018, the owner or operator must maintain records of the make and model of each type of continuous bleed, natural gas-driven pneumatic controllers placed in service on or after January 1, 2018, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is less than or equal to 6 standard cubic feet of gas per hour. Owners or operators must use this information to update the estimate required in Section III.E.1.a.(i) every three years (i.e., by January 1, 2022, January 1, 2025, etc.).
- III.E.1.b. Continuous bleed, natural gas-driven pneumatic controllers located at a natural gas processing plant:
 - III.E.1.b.(i) By January 1, 2019, owners or operators must compile an estimate of the total number of continuous bleed, natural gas-driven pneumatic controllers in service prior to January 1, 2018, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is zero.
 - III.E.1.b.(ii) Beginning January 1, 2018, the owner or operator must maintain records of the make and model of each type of continuous bleed, natural gas-driven pneumatic controllers placed in service on or after January 1, 2018, and documentation (e.g., manufacturer specification, engineering calculations) that the natural gas bleed rate is zero. Owners or operators must use this information to update the estimate required in Section III.E.1.b.(i) every three years (i.e., by January 1, 2022, January 1, 2025, etc.).
- III.E.1.c. Records must be maintained for a minimum of five years and made available to the Division upon request.
- III.E.2. This section applies only to pneumatic controllers identified in Sections III.C.1.c. and III.C.2.c. (State Only: and in Section III.C.3.c.).
 - III.E.2.a. The owner or operator must maintain a log of the total number of pneumatic controllers and their associated controller numbers per facility, the total number of pneumatic controllers per company and the associated justification that the pneumatic controllers must be used pursuant to Sections III.C.1.c. and III.C.2.c. (State Only: and in Section III.C.3.c.). The log shall be updated on a monthly basis.
 - III.E.2.b. The owner or operator must maintain a log of necessary maintenance which shall include, at a minimum, inspection dates, the date of the maintenance activity, pneumatic controller number, description of the maintenance performed, results and date of any corrective action taken, and the printed name and signature of the individual performing the maintenance. The log shall be updated on a monthly basis.

- III.E.2.c. Records of maintenance of pneumatic controllers shall be maintained for a minimum of three years and readily made available to the Division upon request.

III.F. (State Only) Pneumatic Controller Inspection and Enhanced Response

III.F.1. General Requirements

- III.F.1.a. Beginning January 1, 2018, owners or operators of natural gas-driven pneumatic controllers in the 8-Hour Ozone Control Area must operate and maintain pneumatic controllers consistent with manufacturer's specifications, if available, or good engineering and maintenance practices.
- III.F.1.b. Beginning May 1, 2020, owners or operators of natural gas-driven pneumatic controllers state-wide must operate and maintain pneumatic controllers consistent with manufacturer's specifications, if available, or good engineering and maintenance practices.

III.F.2. Pneumatic controller inspection

- III.F.2.a. Beginning June 30, 2018, through calendar year 2019, owners or operators of natural gas-driven pneumatic controllers at well production facilities in the 8-Hour Ozone Control Area must inspect pneumatic controllers using an approved instrument monitoring method at least
 - III.F.2.a.(i) Annually at well production facilities with uncontrolled actual volatile organic compound emissions greater than or equal to one (1) ton per year and less than or equal to six (6) tons per year, based on a rolling twelve-month total.
 - III.F.2.a.(ii) Semi-annually at well production facilities with uncontrolled actual volatile organic compound emissions greater than six (6) tons per year and less than or equal to twelve (12) tons per year, based on a rolling twelve-month total.
 - III.F.2.a.(iii) Quarterly at well production facilities with uncontrolled actual volatile organic compound emissions greater than twelve (12) tons per year and less than or equal to twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.
 - III.F.2.a.(iv) Monthly at well production facilities with uncontrolled actual volatile organic compound emissions greater than twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.
- III.F.2.b. Beginning calendar year 2020, owners or operators of natural gas-driven pneumatic controllers at well production facilities must inspect pneumatic controllers using an approved instrument monitoring method at least:

- III.F.2.b.(i) Annually at well production facilities in the 8-Hour Ozone Control Area with uncontrolled actual volatile organic compound emissions greater than or equal to one (1) ton per year and less than two (2) tons per year, based on a rolling twelve-month total.
- III.F.2.b.(ii) Semi-annually at well production facilities statewide with uncontrolled actual volatile organic compound emissions greater than or equal to two (2) tons per year and less than or equal to twelve (12) tons per year, based on a rolling twelve-month total.
- III.F.2.b.(iii) Quarterly at well production facilities statewide with uncontrolled actual volatile organic compound emissions greater than twelve (12) tons per year and less than or equal to twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.
- III.F.2.b.(iv) Monthly at well production facilities statewide with uncontrolled actual volatile organic compound emissions greater than twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.
- III.F.2.c. For purposes of Sections III.F.2.a. and III.F.2.b., the estimated uncontrolled actual VOC emissions from the highest emitting storage tank at the well production facility determines the frequency at which inspections must be performed. If no storage tanks storing oil or condensate are located at the well production facility, owners or operators must rely on the facility emissions (controlled actual VOC emissions from all permanent equipment, including emissions from components determined by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates).
- III.F.2.d. Beginning June 30, 2018, owners or operators of natural gas-driven pneumatic controllers at natural gas compressor stations in the 8-Hour Ozone Control Area must inspect pneumatic controllers using an approved instrument monitoring method at least:
 - III.F.2.d.(i) Quarterly at natural gas compressor stations with fugitive volatile organic compound emissions greater than zero (0) and less than or equal to fifty (50) tons per year, based on a rolling twelve-month total.
 - III.F.2.d.(ii) Monthly at natural gas compressor stations with fugitive volatile organic compounds greater than fifty (50) tons per year, based on a rolling twelve-month total.
- III.F.2.e. Beginning calendar year 2020, owners or operators of natural gas-driven pneumatic controllers at natural gas compressor stations outside the 8-Hour Ozone Control Area must inspect pneumatic controllers using an approved instrument monitoring method at least:

- III.F.2.e.(i) Semi-annually at natural gas compressor stations with fugitive volatile organic compound emissions greater than zero (0) and less than or equal to twelve (12) tons per year, based on a rolling twelve-month total.
- III.F.2.e.(ii) Quarterly at natural gas compressor stations with fugitive volatile organic compound emissions greater than twelve (12) and less than or equal to fifty (50) tons per year, based on a rolling twelve-month total.
- III.F.2.e.(iii) Monthly at natural gas compressor stations with fugitive volatile organic compounds greater than fifty (50) tons per year, based on a rolling twelve-month total.

III.F.2.f. For purposes of Sections III.F.2.d. and III.F.2.e., fugitive emissions must be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), or other Division approved method.

III.F.2.g. Where detectable emissions from the pneumatic controller are observed, owners or operators must determine whether the pneumatic controller is operating properly within five (5) working days after detecting emissions. In making this determination, owners or operators may use techniques other than approved instrument monitoring methods.

III.F.2.h. For pneumatic controllers not operating properly, the owner or operator must conduct enhanced response or follow manufacturer specifications to return the pneumatic controller to proper operation.

III.F.3. Enhanced response and remonitoring

III.F.3.a. Enhanced response must begin no later than five (5) working days and the pneumatic controller returned to proper operation no later than thirty (30) working days after determining the pneumatic controller is not operating properly, unless parts are unavailable, the equipment requires shutdown to complete enhanced response, or other good cause exists. If parts are unavailable, they must be ordered promptly and enhanced response conducted within fifteen (15) working days of receipt of the parts. If shutdown is required, enhanced response must be conducted during the next scheduled shutdown. If delay is attributable to other good cause, enhanced response must be completed within fifteen (15) working days after the cause of delay ceases to exist.

III.F.3.b. Within fifteen (15) working days of completion of enhanced response, the owner or operator must verify the pneumatic controller is operating properly. In verifying proper operation, owners or operators may use techniques other than approved instrument monitoring methods.

III.F.3.c. Pneumatic controllers found emitting detectable emissions are not subject to enforcement by the Division unless the owner or operator fails to determine whether the pneumatic controller is operating properly in accordance with Section III.F.2., perform any necessary enhanced response in accordance with Section III.F.3., keep records in accordance with Section III.F.4., or submit reports in accordance with Section III.F.5.

III.F.4. Owners or operators must maintain the following records for a minimum of three (3) years and make records available to the Division upon request.

- III.F.4.a. The date, facility name, facility AIRS ID or facility location if the facility does not have an AIRS ID, and approved instrument monitoring method used for each inspection;
- III.F.4.b. A list of pneumatic controllers, including type, determined to be not operating properly;
- III.F.4.c. For intermittent pneumatic controllers observed to have detectable emissions but determined to be operating properly, a brief explanation of the basis for concluding that the intermittent pneumatic controller was operating properly. The explanation can include, but is not limited to, an owner or operator's standard operating procedure detailing how to determine whether an intermittent pneumatic controller is operating properly, or an individual explanation;
- III.F.4.d. The date(s) of enhanced response and a description of the actions taken to return the pneumatic controller to proper operation;
- III.F.4.e. The date the owner or operator verified the pneumatic controller was returned to proper operation; and
- III.F.4.f. The delayed repair list, including the date and duration of any period where the enhanced response was delayed beyond thirty (30) days after determining the pneumatic controller is not operating properly due to unavailable parts, required shutdown, or delay for other good cause, the basis for the delay, and the schedule for returning the pneumatic controller to proper operation. Delay of enhanced response due to unavailable parts must be reviewed, and a record kept of that review, by a representative of the owner or operator with responsibility for pneumatic controller inspection and enhanced response compliance functions. This review will not be made by the individual making the initial determination to place a part on the delayed repair list.

III.F.5. Owners or operators of pneumatic controllers at well production facilities or natural gas compressor stations must submit a single annual report on or before May 31st of each year (beginning May 31st, 2019 for facilities in the 8-Hour Ozone Control Area and May 31st, 2021, for facilities outside the 8-Hour Ozone Control Area) that includes, at a minimum, the following information regarding pneumatic controller inspection and enhanced response activities at their subject facilities conducted the previous calendar year:

- III.F.5.a. The total number and type of pneumatic controllers returned to proper operation, the types of actions taken to return the pneumatic controllers to proper operation, and the facility type (by inspection frequency tier of well production facility or natural gas compressor station);
- III.F.5.b. The number and type of pneumatic controllers on the delayed repair list as of December 31st broken out by the facility type (by inspection frequency tier of well production facility or natural gas compressor station), and the basis for each delay; and

III.F.5.c. The record of all reviews conducted for delayed repairs due to unavailable parts extending beyond 30 days for the previous calendar year.

III.F.6. The provisions in Section III.F. will be reassessed by the Division and stakeholders in 2020.

IV. (State Only) Control of Emissions from the Natural Gas Transmission and Storage Segment

IV.A. Definitions

IV.A.1. “Best management practice” (BMP) means a demonstrated and commercially available or innovative emission-reducing technology or work practice.

IV.A.2. “Best management practices plan” (BMP plan) means a written plan that includes, but is not limited to, each natural gas transmission and storage segment owner or operator’s planned and implemented BMPs to reduce methane emissions from its facilities within the natural gas transmission and storage segment.

IV.A.3. “Natural gas transmission and storage segment” (segment) includes onshore natural gas transmission pipelines, onshore natural gas transmission compression, underground natural gas storage, and liquefied natural gas (LNG) storage, as these terms are defined in 40 CFR Part 98, Section 98.230 (October 22, 2015), that are physically located in Colorado.

IV.A.4. “Natural gas transmission and storage segment Colorado throughput” (segment throughput) means the total volume of natural gas, as adjusted for methane, transported through transmission pipelines in Colorado as reported to the Department of Energy’s (DOE) Energy Information Administration (EIA) for Form 176, excluding net volumes stored as liquefied natural gas or in underground storage facilities.

IV.A.5. “Natural gas transmission and storage segment emissions inventory protocol” (inventory protocol) means the requirements by which natural gas transmission and storage segment owners or operators will quantify and report methane, ethane, carbon monoxide (CO), carbon dioxide (CO₂), nitrous oxide (N₂O), nitrogen oxides (NO_x), and volatile organic compound (VOC) emissions. The protocol will specify the segment facilities and types of activity data collected, emissions quantification methodologies, throughput calculation methodologies, criteria for determining whether events are beyond the control of the owner or operator, and the process for designating and protecting confidential business information (CBI), consistent with Colorado law.

IV.A.6. “Performance-based program” means a program of BMPs implemented and documented by each natural gas transmission and storage segment owner or operator to reduce methane emissions in order to achieve the system-wide emissions intensity target.

IV.A.7. “Steering committee” means five members approved by the Division to serve as a technical working group for developing program guidance documents and evaluating progress against the system-wide emissions intensity target. The committee members will include two representatives from natural gas transmission and storage segment owners or operators (or industry trade organizations representing owners or operators), two members representing the general public (including but not limited to environmental organizations, local government groups, or citizens), and one Division member.

- IV.A.8. "Segment-wide emissions intensity" means the natural gas transmission and storage segment methane emissions divided by the natural gas transmission and storage segment throughput.
- IV.A.9. "Segment-wide emissions intensity target" (segment-wide target) means the target established by the steering committee reflected as annual segment-wide methane emissions from Colorado's natural gas transmission and storage segment divided by the annual natural gas transmission and storage segment Colorado throughput.
- IV.B. Beginning January 1, 2020, each segment owner or operator must participate in this performance based program to reduce segment-wide methane emissions.
- IV.B.1. By April 1, 2020, a steering committee charter and the steering committee members will be approved by the Division.
- IV.B.2. By September 30, 2020, the Division will publish the inventory protocol and any associated program guidance documents developed by the steering committee.
- IV.B.3. By December 31, 2020, each segment owner or operator must develop a company-specific BMP plan. The BMP plan must contain each element from the BMP plan template chapter of the program guidance document, which will include, but is not limited to, a list of information the owner or operator must collect to demonstrate the BMPs performed. By December 31st of each year (beginning December 31st, 2021), each owner or operator must review and update, as appropriate, its company-specific BMP plan and document in the BMP plan any changes.
- IV.B.4. Beginning January 1, 2021, each segment owner or operator will
- IV.B.4.a. Implement company specific BMP plans.
- IV.B.4.b. Collect emissions inventory data in accordance with the inventory protocol and its company-specific BMP plan.
- IV.B.5. By May 1, 2022, the segment owners or operators will select a third-party contractor from a pool of qualified applicants to receive, safeguard, and aggregate company-specific reports as described in Sections IV.D.3. and IV.D.4. The steering committee will establish criteria for the selection of the third-party contractor. The segment owners and operators will use a competitive bidding process to solicit applications from contractors who meet the criteria and will provide an opportunity for the steering committee to reject unqualified applicants.
- IV.B.6. By October 1, 2023, the steering committee will determine the segment-wide emissions intensity target using the 2021 and 2022 emissions inventory data. In developing the initial or updated segment-wide emissions intensity target and evaluating the program, the steering committee may request non-company specific information from the Division (in accordance with the Colorado Open Records Act) or the third-party contractor to assist in setting such target or such evaluation. The steering committee may ask companies to explain emission factors and methodologies used to calculate or measure emissions.
- IV.C. The segment-wide emissions intensity target must first be achieved by January 1, 2025, based on the 2024 reporting year.

- IV.C.1. By October 1 of each year (beginning October 1, 2025), the steering committee will submit a compliance certification to the Division that the segment achieved the segment-wide emissions intensity target for the prior calendar year.
- IV.C.2. If the steering committee cannot certify compliance with the segment-wide emissions intensity target, the steering committee will develop a plan (which may include amendments to program guidance documents) and timeline for the segment to achieve compliance with the segment-wide emissions intensity target.
- IV.C.3. Beginning January 1, 2026, and every three (3) years thereafter if appropriate, the steering committee will assess the segment-wide emissions intensity target for continual improvement.
- IV.D. Recordkeeping and reporting
 - IV.D.1. The Division will provide an update on the development of this program and initial implementation efforts to the Air Quality Control Commission during a scheduled Commission meeting on or after January 2021.
 - IV.D.2. Segment owners or operators must maintain BMP plans and emissions inventory reports for a period of five (5) years and make records available to the Division upon request.
 - IV.D.3. By June 30 of each year (beginning June 30, 2022), owners or operators of the natural gas transmission and storage segment will submit company-wide reports to the third-party contractor.
 - IV.D.3.a. Emissions claimed to be beyond the control of the owner or operator, using the criteria and methods established by the steering committee, must be included in the company-wide report but will not be used to set or determine compliance with the segment-wide emissions intensity target.
 - IV.D.3.b. Emissions and emission reductions associated with any requirements of the Pipeline and Hazardous Materials Safety Administration (PHMSA), the Colorado Public Utilities Commission (CPUC), and/or the Federal Energy Regulatory Commission (FERC) must be included in the report and used for purposes of calculating compliance with the system-wide emissions intensity target, unless they qualify under Section IV.D.3.a., but this Section IV. does not supersede or alter these agencies applicable regulations or requirements.
 - IV.D.4. The third-party contractor must aggregate the company-wide reports into a segment-wide report and provide it to the steering committee by August 15 of each year (beginning August 15, 2022) on a form developed by the steering committee and approved by the Division. The segment-wide report must include, at a minimum
 - IV.D.4.a. The segment-wide emissions, apportioned by county,
 - IV.D.4.b. A report of the numbers and types of events subject to Section IV.D.3.a. and the segment-wide emissions resulting from each type of event.
 - IV.D.4.c. The BMPs implemented to mitigate or avoid emissions and a description of how the BMPs mitigate, reduce, and/or avoid emissions.
 - IV.D.4.d. The segment-wide segment throughput.

- IV.D.4.e. The segment-wide emissions intensity. If the steering committee determines that one or more types of events reported under Section IV.D.4.b. were not beyond the control of the owner or operator, the steering committee will revise the segment-wide emissions intensity calculation to include the methane emissions from those events.
- IV.D.5. Segment owners or operators must submit an annual certification to the Division by June 30 of each year (beginning June 30, 2021) that includes
 - IV.D.5.a. A certification that the company-specific BMP plan was developed or reviewed in accordance with Section IV.B.3.
 - IV.D.5.b. A certification that the company-wide report was submitted to the third-party contractor in accordance with Section IV.D.3.
 - IV.D.5.c. Beginning in 2022, a certification of company BMP plan compliance in accordance with Section IV.B.4., including
 - IV.D.5.c.(i) The company's implementation of the BMPs in the company-specific BMP plan.
 - IV.D.5.c.(ii) Instances of non-conformance with the company-specific BMP plan, reason(s) for non-conformance, and any modifications of the applicable element(s) of the BMP plan.
 - IV.D.5.c.(iii) Any use of alternative emission reduction approaches not specified in the company-specific BMP plan.
 - IV.D.5.d. With each submission under Sections IV.D.5.a. through IV.D.5.c., a certification by a responsible official that, based on information and belief after reasonable inquiry, the statements and information in the document are true, accurate, and complete.
- IV.D.6. The Division may provide an update briefing to the Air Quality Control Commission during a scheduled Commission meeting on or after October 1 of each year (beginning October 1, 2022). The update briefing will include any assessment of the segment-wide target, as specified in Section IV.C.3.

V. (State Only) Oil and Natural Gas Operations Emissions Inventory

V.A. Applicability

- V.A.1. On or before June 30th, 2021 (and on June 30th each year thereafter), the owner or operator of oil and natural gas operations and equipment at or upstream of a natural gas processing plant in Colorado must submit a single annual report that includes actual emissions and specified information in the Division-approved report format.
- V.A.2. On or before June 30th, 2022 (and on June 30th each year thereafter), the owner or operator of class II disposal well facilities that are not subject to reporting under Section IV. must submit a single annual report that includes actual emissions and specified information in the Division-approved report format.

V.B. General reporting requirements

V.B.1. The following information must be reported in accordance with Section V.A.

- V.B.1.a. Company name, physical street address, and name and contact information of the company representative, for reporting purposes.
- V.B.1.b. The date of submittal and the year covered by the report.
- V.B.1.c. A list of the activities or equipment, as specified in Section V.C., for which emissions are reported.
- V.B.1.d. The company's monthly actual emissions of volatile organic compounds (VOC), oxides of nitrogen (NO_x), nitrous oxide (N₂O), carbon dioxide (CO₂), carbon monoxide (CO), methane, and ethane for each month of May through September.
- V.B.1.e. The company's annual actual emissions of VOCs, NO_x, N₂O, CO₂, CO, methane, and ethane for the entire calendar year.
- V.B.1.f. The actual emissions of VOCs, NO_x, N₂O, CO₂, CO, methane, and ethane for each activity or equipment listed in Section V.C. per facility, or per pipeline between facilities where the pipeline is not located at a stationary source.
 - V.B.1.f.(i) The report must include the actual emissions from each activity or equipment per month for each month of May through September.
 - V.B.1.f.(ii) The report must include the actual emissions from each activity or equipment for the entire calendar year.
- V.B.1.g. A certification by the company representative that supervised the development and submission of the inventory report that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

V.B.2. The owner or operator must submit a revised annual report after discovering that an annual report submitted within the previous two (2) years contained one or more substantive errors. A substantive error is a mass of emissions of any individual pollutant subject to reporting under Section V. that is at least 10% higher or lower than the mass of emissions of the pollutant reported across the owner or operator's activity or equipment, as listed in Section V.C., in Colorado. A refinement of or improvement to an emissions estimation technique or emission factor is not a substantive error but must be noted in the subsequent annual report after the refinement or improvement. Revised annual reports must be submitted by August 31 if the substantive error is discovered between January 1 and June 30, and by February 28 if the substantive error is discovered between July 1 and December 31 of the preceding calendar year.

V.C. Beginning July 1, 2020, and each calendar year thereafter, owners or operators must maintain the following information for inclusion in the annual report, except that beginning January 1, 2021, owners or operators must maintain the information described in Sections V.C.2.g. and V.C.2.h. Beginning May 1, 2021, owners or operators of class II disposal well facilities must maintain the following information for inclusion in the annual report.

- V.C.1. AIRS number of the activity or equipment and associated facility or pipeline (if a pipeline between facilities) location, including latitude and longitude coordinates. If the activity or equipment does not have an AIRS number, a description of the activity or equipment.
- V.C.2. Actual emissions from each activity or equipment listed below, unless otherwise specified in the Division-approved report format, and the emission factor(s), assumptions, and calculation methodology used to calculate the emissions.
 - V.C.2.a. Abnormal events, except those reported as malfunctions under the Common Provisions or in another activity or equipment.
 - V.C.2.b. Acid gas removal units.
 - V.C.2.c. Associated gas venting and flaring, aggregated per facility.
 - V.C.2.d. Blowdowns from facility equipment piping where the physical volume of the piping between isolation valves is greater than or equal to 50 cubic feet, aggregated per activity below per facility.
 - V.C.2.d.(i) Pipeline venting within the facility boundary.
 - V.C.2.d.(ii) Compressors.
 - V.C.2.d.(iii) Scrubbers/strainers.
 - V.C.2.d.(iv) Pig launchers and receivers.
 - V.C.2.d.(v) Emergency shutdowns (regardless of equipment type).
 - V.C.2.d.(vi) All other equipment (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) with a physical volume between isolation valves greater than or equal to 50 cubic feet.
 - V.C.2.e. Boilers.
 - V.C.2.f. Centrifugal compressor leaks or vents, aggregated per facility.
 - V.C.2.g. Class II disposal well facility fluids accepted for injection. Owners or operators will take periodic, representative samples of the liquids for estimating emissions for the annual report.
 - V.C.2.h. Class II disposal well facility produced water ponds.
 - V.C.2.i. Drilling mud and mud pits.
 - V.C.2.j. Flares and enclosed combustion devices, where not otherwise reported in the emissions of another emissions source category.
 - V.C.2.k. Fugitive emissions from components, aggregated per facility.
 - V.C.2.l. Hydrocarbon liquid storage tanks.
 - V.C.2.m. Hydrocarbon liquid loadout.

V.C.2.n.	Maintenance and safety, where not otherwise reported in the emissions of another emissions source category.
V.C.2.o.	Natural gas dehydration (glycol and desiccant).
V.C.2.p.	Natural gas pneumatic controllers, aggregated per facility.
V.C.2.q.	Natural gas pneumatic pumps, aggregated per facility.
V.C.2.r.	Non-road internal combustion engines.
V.C.2.s.	Pipeline segments between facilities.
V.C.2.t.	Process heaters.
V.C.2.u.	Produced water storage tanks.
V.C.2.v.	Produced water loadout.
V.C.2.w.	Reciprocating compressor leaks or vents, aggregated per facility.
V.C.2.x.	Separators (e.g., two-phase separators, three-phase separators, high/low pressure separators, heater-treaters, vapor recovery towers, etc.).
V.C.2.y.	Stationary combustion turbines.
V.C.2.z.	Stationary compression ignition internal combustion engines.
V.C.2.aa.	Stationary spark ignition internal combustion engines.
V.C.2.bb.	Temporary completion and/or workover equipment (e.g., tanks).
V.C.2.cc.	Thermal oxidizing units, where not otherwise reported in the emissions of another emissions source category.
V.C.2.dd.	Well completions (includes flowback).
V.C.2.ee.	Well workovers.
V.C.2.ff.	Wellhead bradenhead.

VI. (State Only) Oil and Natural Gas Pre-Production and Early Production Operations

VI.A. Definitions

VI.A.1. "Commencement of operation" means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).

- VI.A.2. "Drill-out" means the process of removing the plugs placed during hydraulic fracturing or refracturing. Drill-out ends after the removal of all stage plugs and the initial wellbore clean-up.
- VI.A.3. "Drilling" or "drilled" means the process to bore a hole to create a well for oil and/or natural gas production.
- VI.A.4. "Flowback" means the process of allowing fluids and entrained solids to flow from a well following stimulation, either in preparation for a subsequent phase of treatment or in preparation for cleanup and placing the well into production. The term flowback also means the fluids and entrained solids flowing from a well after drilling or hydraulic fracturing or refracturing. Flowback ends when all temporary flowback equipment is removed from service. Flowback does not include drill-out.
- VI.A.5. "Flowback vessel" means a vessel that contains flowback.
- VI.A.6. "Hydraulic fracturing" means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale, coal, and tight sand formations, that subsequently require flowback to expel fracture fluids and solids.
- VI.A.7. "Hydraulic refracturing" means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.
- VI.A.8. "Pre-production operations" means the drilling through the hydrocarbon bearing zones, hydraulic fracturing or refracturing, drill-out, and flowback of an oil and/or natural gas well.
- VI.A.9. "Tank measurement system" means equipment and methods used to determine the quantity of the liquids inside a flowback vessel without requiring direct access through the flowback vessel thief hatch or other opening.
- VI.A.10. "Well" means a hole drilled for the purpose of producing oil and/or natural gas.
- VI.A.11. "Well completion" means the process that allows for the flow of petroleum and/or natural gas from newly drilled wells, to expel drilling and reservoir fluids, and to test the reservoir flow characteristics (e.g., hydraulic fracturing, drill-out, flowback).
- VI.A.12. "Well re-completion" means the process that allows for the flow of petroleum and/or natural gas from an existing well from any geological interval not currently producing in the existing well, to expel drilling and reservoir fluids, and to test the reservoir flow characteristics (e.g., hydraulic re-fracturing, drill-out, flowback).
- VI.B. General provisions
- VI.B.1. At all times the facility and equipment must be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions.
- VI.B.2. Air pollution control equipment must be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable and consistent with technological limitations and good engineering and maintenance practices.
- VI.C. Air quality monitoring
- VI.C.1. Owners or operators of drilling operations that begin on or after May 1, 2021, must monitor air quality at and/or around the pre-production and early production operations.

- VI.C.1.a. Owners or operators must monitor air quality for at least ten (10) days prior to beginning pre-production operations, during all pre-production operations, and for at least six months after the well is capable of consistently producing either separable gas or salable liquid hydrocarbons (i.e., early production).
- VI.C.1.b. Owners or operators must submit an air quality monitoring plan to the Division and the local government with jurisdiction over the location of the operations and any other local government unit, where applicable, within 2,000 feet of the proposed operations at least sixty (60) days prior to beginning air quality monitoring. Upon the request of any of these local government units within 14 days of receiving the plan, the Division will consult with them as part of its review process. Owners or operators must receive approval from the Division of the air quality monitoring plan prior to beginning air quality monitoring. Owners or operators must comply with the plan once approved. The air quality monitoring plan must include, at a minimum:
- VI.C.1.b.(i) The owner or operator name and the contact information of the owner or operator representative for monitoring purposes.
 - VI.C.1.b.(ii) The planned schedule for drilling and pre-production operations.
 - VI.C.1.b.(iii) The operations to be monitored including the API number of the well(s), location of the operations including latitude and longitude coordinates, and any associated facility or equipment AIRS number(s).
 - VI.C.1.b.(iv) Whether the local government with jurisdiction over the location of the operations has air quality monitoring requirements applicable to pre-production and/or early production operations, a description of those requirements, and a local government contact for air quality monitoring purposes.
 - VI.C.1.b.(v) The monitoring objective(s), which must include one or more of the following (and may include additional objectives such as field-testing new air quality monitoring technologies or improving emissions inventories):
 - VI.C.1.b.(v)(A) Detect, evaluate, and reduce as necessary hazardous air pollutant emissions;
 - VI.C.1.b.(v)(B) Detect, evaluate, and reduce as necessary ozone precursor emissions;
 - VI.C.1.b.(v)(C) Detect, evaluate, and reduce as necessary methane emissions.

- VI.C.1.b.(vi) The air pollutant(s) and other parameters to be monitored. Pollutants must include at least one of the following: total VOCs, methane, benzene or BTEX (benzene, toluene, ethyl benzene and xylenes) or other indicator of hydrocarbon emissions from pre-production and early production operations, as appropriate to meeting the specified monitoring objectives.
- VI.C.1.b.(vii) A description of the monitoring equipment to be deployed, including the manufacturer and model information and any manufacturer specifications for the monitoring equipment and data systems. The description of pollutant monitoring equipment should explain why it was chosen and document or provide references describing relevant prior use and evaluations that are known to the owner or operator.
- VI.C.1.b.(viii) A description of the meteorological monitoring equipment to be deployed. If meteorological data will not be collected on-site, the plan must provide reasoning and justification, and identify the meteorological station from which data will be obtained and demonstrate that the station represents conditions at the oil and gas development site.
- VI.C.1.b.(ix) A monitor siting plan, which must include but is not limited to:
- VI.C.1.b.(ix)(A) The number of monitors and/or sensors to be deployed.
 - VI.C.1.b.(ix)(B) The location and height of the monitoring equipment, including for each phase of operations if location and height of the equipment will change (e.g., monitoring placement impacted by sound walls).
 - VI.C.1.b.(ix)(C) A topographic map and plan of the site, showing the expected equipment layout, including air quality and meteorological monitor locations and their distance from pre-production and production operations. The map must indicate any obstructions to air flow to the monitor(s) and also show all roads and access ways within a half-mile of the facility and any contiguous structures, whether or not they are part of the production operations.
 - VI.C.1.b.(ix)(D) A description of how the placement of monitoring equipment minimizes surface disturbances, in alignment with the Colorado Oil and Gas Conservation Commission's site preparation requirements.
 - VI.C.1.b.(ix)(E) An explanation of how the number and placement of monitoring equipment will be adequate to achieve the desired air quality monitoring objectives, considering the monitoring equipment's detection limit and other limitations.
- VI.C.1.b.(x) The standard operating procedures that will be employed, to include at minimum:

- VI.C.1.b.(x)(A) The sampling and/or measurement interval, averaging times, minimum detection concentration or level, expected precision, and confidence level at which pollutant data will be reported.
- VI.C.1.b.(x)(B) The response level for each pollutant or indicator monitored and/or sampled and the response procedures or actions that will be taken if elevated levels are observed.
- VI.C.1.b.(x)(C) The data quality indicators for precision and bias of the monitoring equipment.
- VI.C.1.b.(x)(D) The quality control and quality assurance procedures, including calibration intervals and frequency, which will be used to ensure proper operation of the monitoring equipment. Owners or operators may reference and attach an existing methodology.
- VI.C.1.b.(x)(E) A discussion of known limitations of the pollutant monitoring equipment and, if applicable, how they will be addressed.
- VI.C.1.b.(x)(F) The protocol that will be used for acquiring, processing, and recording relevant meteorological data.
- VI.C.1.b.(x)(G) The data system and operating protocol to be used for data collection, including, but not limited to, data logging, data processing, recording, downloading, backup and storage, and reporting.
- VI.C.1.b.(x)(H) The methods for collecting and analyzing speciated or other samples of chemical constituents identified by the Division when indicated necessary based on site-specific concentration thresholds, if applicable.
- VI.C.1.b.(xi) A description of how the monitoring equipment, pollutant(s) monitored, and siting plan are expected to detect elevated emissions and achieve at least one of the monitoring objectives listed in Section VI.C.1.b.(v).

VI.C.1.c. Within ten (10) days of approving a monitoring plan, the Division will notify all local government units identified in Section VI.C.1.b. of the plan approval.

VI.C.2. Recordkeeping and reporting

VI.C.2.a. Owners or operators must keep the following records for a minimum of three (3) years, unless otherwise specified, and upon request make records available to the Division. Local governments identified in Section VI.C.1.b may request those records from the Division. If the Division has not requested the records and a local government(s) identified in Section VI.C.1.b requests the records from the Division, the Division shall request the records from the owner or operator.

- VI.C.2.a.(i) The air quality monitoring plan.
- VI.C.2.a.(ii) Monthly reports and the data necessary to inform the monthly reports, as provided in Section VI.C.2.b.
- VI.C.2.a.(iii) Activity logs to inform Section VI.C.2.b.(iii)(A) of the monthly report.
- VI.C.2.a.(iv) For a period of one year after the monthly report, the underlying raw data associated with each monitor.
- VI.C.2.a.(v) For a period of one year after the monthly report, the meteorological data in the time intervals as close to the sampling and/or measurement intervals as possible.
- VI.C.2.b. Owners or operators must submit monthly reports of monitoring conducted to the Division by the last day of the month following the previous month of monitoring (e.g., by June 30 for the previous May 1-31), including
 - VI.C.2.b.(i) The month and year of the monitoring period.
 - VI.C.2.b.(ii) A description of the monitoring equipment and the pollutant(s) monitored.
 - VI.C.2.b.(iii) A description of the monitored operations including
 - VI.C.2.b.(iii)(A) The phase of operation (e.g., prior to pre-production, during pre-production operations, early production) and activities occurring during the monitored period.
 - VI.C.2.b.(iii)(B) API number of the well(s).
 - VI.C.2.b.(iii)(C) Location of the operations, including latitude and longitude coordinates.
 - VI.C.2.b.(iii)(D) Any associated facility or equipment AIRS number(s).
 - VI.C.2.b.(iii)(E) The date, time, and duration of any monitoring equipment downtime.
 - VI.C.2.b.(iii)(F) The date, time, and duration of operations malfunctions and shut-in periods or other events investigated for influence on monitoring.
 - VI.C.2.b.(iv) For the first monthly report after beginning monitoring during pre-production operations, a summary of air quality condition results monitored prior to beginning pre-production operations, including time series of the results at hourly or higher time resolution and a statistical summary of the air quality results monitored prior to beginning pre-production operations, including number of observations, maximum concentrations or levels, periodic averages, and data distributions including 5th, 25th, median, 75th and 95th percentile values.

- VI.C.2.b.(v) A summary of monitored air quality results, including time series plots as hourly or higher time resolution and a statistical summary including number of observations, maximum concentrations or levels, periodic averages, and date distributions including 5th, 25th, median, 75th and 95 percentile values.
- VI.C.2.b.(vi) A description of responsive action(s) taken as a result of monitoring results, including the date; concentration or level measured; correlations with specific events, activities, and/or monitoring thresholds; and any additional steps taken as a result of the responsive action.
- VI.C.2.b.(vii) The results of any speciated or other samples of chemical constituents identified by the Division and collected when site-specific concentrations indicate such samples are necessary.
- VI.C.2.b.(viii) A summary of meteorological data, including in the time intervals identified for concentration readings in the air quality monitoring plan during the time period of responsive action(s). If meteorological data is collected on-site, the meteorological data assessed in as close to the sampling and/or measurement intervals as possible.
- VI.C.2.b.(ix) A description of how data will be processed, if available from the manufacturer, and summarized for purposes of fulfilling monthly reporting requirements, including whether and how data will be corrected, and how missing data and values that are below detection limits will be treated in statistical summaries.
- VI.C.2.b.(x) In the last monthly report, a certification by the company representative that supervised the development and submission of the monitoring reports that, based on information and belief formed after reasonable inquiry, the statements and information in the monthly reports are true, accurate, and complete.

VI.C.3. Owners or operators must notify the Division and the local government with jurisdiction over the location of the operations, using the contact provided in Section VI.C.1.b.(iv), within forty-eight (48) hours of responsive action(s) taken as a result of recorded values in excess of the response level.

VI.D. Emission reduction from pre-production flowback vessels

VI.D.1. Control

- VI.D.1.a. Owners or operators of a well with flowback that begins on or after May 1, 2021, must collect and control emissions from each flowback vessel on and after the date flowback is routed to the flowback vessel by routing emissions to and operating air pollution control equipment that achieves a hydrocarbon control efficiency of at least 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons.

- VI.D.1.a.(i) Owners or operators must use enclosed, vapor-tight flowback vessels.
- VI.D.1.a.(ii) Flowback vessels must be inspected, tested, and refurbished where necessary to ensure the flowback vessel is vapor-tight prior to receiving flowback.
- VI.D.1.a.(iii) Owners or operators must use a tank measurement system to determine the quantity of liquids in the flowback vessel(s).
 - VI.D.1.a.(iii)(A) Thief hatches or other access points to the flowback vessel must remain closed and latched during activities to determine the quantity of liquids in the flowback vessel(s).
 - VI.D.1.a.(iii)(B) Opening the thief hatch or other access point if required to inspect, test, or calibrate the tank measurement system or to add biocides or chemicals is not a violation of Section VI.D.1.a.(ii)(A).
- VI.D.1.a.(iv) Combustion devices used during pre-production operations must be enclosed, have no visible emissions during normal operation, and be designed so that an observer, by means of visual observation from the outside of the enclosed combustion device, or by other means approved by the Division, determine whether it is operating properly.
 - VI.D.1.a.(iv)(A) Combustion devices must be equipped with an operational auto-igniter upon installation of the combustion device.

VI.D.2. Monitoring

- VI.D.2.a. Owners or operators of a well with flowback that begins on or after May 1, 2021, must conduct daily visual inspections of the flowback vessel and any associated equipment.
 - VI.D.2.a.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly seated.
 - VI.D.2.a.(ii) Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating.
 - VI.D.2.a.(iii) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the flowback vessel to the air pollution control equipment are open.
 - VI.D.2.a.(iv) If a combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light to ensure they are functioning properly.

- VI.D.2.a.(v) If a combustion device is used, inspection of the device for the presence or absence of smoke. If smoke is observed, either the equipment must be immediately shut-in to investigate the potential cause for smoke and perform repairs, as necessary, or EPA Method 22 must be conducted to determine whether visible emissions are present for a period of at least one (1) minute in fifteen (15) minutes.

VI.D.3. Recordkeeping

- VI.D.3.a. The owner or operator of each flowback vessel subject to Section VI.D.1. must maintain records for a period of two (2) years and make them available to the Division upon request, including
 - VI.D.3.a.(i) The API number of the well and the associated facility location, including latitude and longitude coordinates.
 - VI.D.3.a.(ii) The date and time of the onset of flowback.
 - VI.D.3.a.(iii) The date and time the flowback vessels were permanently disconnected, if applicable.
 - VI.D.3.a.(iii) The date and duration of any period where the air pollution control equipment is not operating.
 - VI.D.3.a.(iv) Records of the inspections required in Section VI.D.2. including the time and date of each inspection, a description of any problems observed, a description and date of any corrective action(s) taken, and the name of the employee or third party performing corrective action(s).
 - VI.D.3.a.(v) Where a combustion device is used, the date and result of any EPA Method 22 test or investigation pursuant to Section VI.D.2.a.(v).

PART E Combustion Equipment and Major Source RACT

I. Control of Emissions from Engines

I.A. Requirements for new and existing engines.

- I.A.1. The owner or operator of any natural gas-fired stationary or portable reciprocating internal combustion engine with a manufacturer's design rate greater than 500 horsepower commencing operations in the 8-hour Ozone Control Area on or after June 1, 2004 shall employ air pollution control technology to control emissions, as provided in Section I.B.
- I.A.2. Any existing natural gas-fired stationary or portable reciprocating internal combustion engine with a manufacturer's design rate greater than 500 horsepower, which existing engine was operating in the 8-hour Ozone Control Area prior to June 1, 2004, shall employ air pollution control technology on and after May 1, 2005, as provided in Section I.B.

- I.A.3. Stationary natural gas fired reciprocating internal combustion engines state-wide with a manufacturer's design rate greater than or equal to 1000 horsepower are subject to Section I.D.5.
- I.B. Air pollution control technology requirements
 - I.B.1. For rich burn reciprocating internal combustion engines, a non-selective catalyst reduction and an air fuel controller shall be required. A rich burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.
 - I.B.2. For lean burn reciprocating internal combustion engines, an oxidation catalyst shall be required. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.
 - I.B.3. The emission control equipment required by this Section I.B shall be appropriately sized for the engine and shall be operated and maintained according to manufacturer specifications.
- I.C. The air pollution control technology requirements in Sections I.A. and I.B. do not apply to:
 - I.C.1. Non-road engines, as defined in Regulation Number 3, Part A, Section I.B.31.
 - I.C.2. Reciprocating internal combustion engines that the Division has determined will be permanently removed from service or replaced by electric units on or before May 1, 2007. The owner or operator of such an engine shall provide notice to the Division of such intent by May 1, 2005 and shall not operate the engine identified for removal or replacement in the 8-hour Ozone Control Area after May 1, 2007.
 - I.C.3. Any emergency power generator exempt from APEN requirements pursuant to Regulation Number 3, Part A.
 - I.C.4. Any lean burn reciprocating internal combustion engine operating in the 8-hour Ozone Control Area prior to June 1, 2004, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than \$5,000 per ton of VOC emission reduction. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by May 1, 2005. Any reciprocating internal combustion engine qualifying for this exemption shall not be moved to any other location within the 8-hour Ozone Control Area.
- I.D. Control of emissions from new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines.
 - I.D.1. (State Only) Exemptions
 - I.D.1.a. The requirements of this Section I.D. do not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

I.D.1.b. Internal combustion engines that are subject to an emissions control requirement in a federally maximum achievable control technology (MACT) standard under 40 CFR Part 63, a Best Available Control Technology (BACT) limit, or a New Source Performance Standard (NSPS) under 40 CFR Part 60 are not subject to Section I.D.3.

I.D.2. (State Only) General Provisions

I.D.2.a. At all times, including periods of start-up and shutdown, engines and their associated equipment must be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether or not acceptable operation and maintenance procedures are being used will be based on information available to the Division, which may include, but is not limited to, monitoring results, opacity observations, review of operation and maintenance procedures, and inspection of the source.

I.D.2.b. All engines and their associated equipment must be operated and maintained pursuant to the manufacturing specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator must keep manufacturer specifications or equivalent on file.

I.D.2.c. Any of the effective dates for installation of controls on internal combustion engines as required in Section I.D.3. may be extended at the Division's discretion for good cause shown.

I.D.3. (State Only) New, Modified and Relocated Natural Gas Fired Reciprocating Internal Combustion Engines

I.D.3.a. Except as provided in Section I.D.3.b., the owner or operator of any natural gas fired reciprocating internal combustion engine that is either constructed or relocated to the state of Colorado from another state, on or after the date listed in Table 1 shall operate and maintain each engine according to the manufacturer's written instructions or procedures to the extent practicable and consistent with technological limitations and good engineering and maintenance practices over the entire life of the engine so that it achieves the emission standards required in Section I.D.3.b. Table 1.

I.D.3.b. Actual emissions from natural gas fired reciprocating internal combustion engines shall not exceed the emission performance standards in Table 1 as expressed in units of grams per horsepower-hour (G/hp-hr)

TABLE 1				
Maximum Engine Hp	Construction or Relocation Date	Emission Standards in G/hp-hr		
		NOx	CO	VOC
< 100 Hp	Any	NA	NA	NA
≥ 100 Hp	On or after January 1, 2008	2.0	4.0	1.0
and < 500 Hp	On or after January 1, 2011	1.0	2.0	0.7
≥ 500 Hp	On or after July 1, 2007	2.0	4.0	1.0
	On or after July 1, 2010	1.0	2.0	0.7

**These engines may also be subject to emission standards under Section I.D.5.*

I.D.4. Existing Natural Gas Fired Reciprocating Internal Combustion Engines

I.D.4.a. (Regional Haze SIP) Rich Burn Reciprocating Internal Combustion Engines

I.D.4.a.(i) Except as provided in Sections I.D.4.a.(i)(B) and (C) and I.E.4.a.(ii), all rich burn reciprocating internal combustion engines with a manufacturer's name plate design rate greater than 500 horsepower, constructed or modified before February 1, 2009 shall install and operate both a non-selective catalytic reduction system and an air fuel controller by July 1, 2010. A rich burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of less than 2% by volume.

I.D.4.a.(i)(A) All control equipment required by this Section I.D.4.a. shall be operated and maintained pursuant to manufacturer specifications or equivalent to the extent practicable, and consistent with technological limitations and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications or equivalent on file.

I.D.4.a.(i)(B) Internal combustion engines that are subject to an emissions control requirement in a federal maximum achievable control technology ("MACT") standard under 40 CFR Part 63 (January 1, 2011), a Best Available Control Technology ("BACT") limit, or a New Source Performance Standard under 40 CFR Part 60 (January 1, 2011) are not subject to this Section I.D.4.a.

I.D.4.a.(i)(C) The requirements of this Section I.D.4.a. do not apply to any engine having actual uncontrolled emissions below permitting thresholds listed in Regulation Number 3, Part B.

I.D.4.a.(ii) Any rich burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than \$ 5,000 per ton of combined volatile organic compound and nitrogen oxides emission reductions (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section I.D.4.a. Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

I.D.4.b. (State Only) Lean Burn Reciprocating Internal Combustion Engines

I.D.4.b.(i) Except as provided in Section I.D.4.b.(ii), all lean burn reciprocating internal combustion engines with a manufacturer's nameplate design rate greater than 500 horsepower shall install and operate an oxidation catalyst by July 1, 2010. A lean burn reciprocating internal combustion engine is one with a normal exhaust oxygen concentration of 2% by volume, or greater.

I.D.4.b.(ii) Any lean burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than \$ 5,000 per ton of volatile organic compound emission reduction (this value shall be adjusted for future applications according to the current day consumer price index) is exempt complying with Section I.D.4.b.(i). Installation costs and the best information available for determining control efficiency shall be considered in determining such costs. In order to qualify for such exemption, the owner or operator must submit an application making such a demonstration, together with all supporting documents, to the Division by August 1, 2009.

I.D.5. (State Only) Additional Requirements for Natural Gas Fired Reciprocating Internal Combustion Engines

I.D.5.a. Applicability

I.D.5.a.(i) This Section I.D.5. applies to stationary natural gas fired reciprocating internal combustion engines state-wide with a manufacturer's design rate greater than or equal to 1000 horsepower.

- I.D.5.a.(i)(A) For purposes of this Section I.D.5., modified means any physical change to the engine or change in method of operation that results in an increase in the emission rate of any air pollutant, and does not include any physical or operational changes excluded by 40 C.F.R. 60.14(e).
- I.D.5.a.(i)(B) For purposes of this Section I.D.5., placed in service means the bringing of an engine on-site for use. The placed in service date is the date the engine begins to operate. The following is not considered placed in service: (1) moving an engine subject to an Alternative Company-Wide Compliance Plan to another site with the same owner or operator; (2) for engines in service on or before November 14, 2020, replacement under an authorized alternative operating scenario.
- I.D.5.a.(i)(C) For purposes of this Section I.D.5., relocated means the bringing of an engine into the 8-Hour Ozone Control Area from outside the 8-Hour Ozone Control Area or the bringing of an engine into the State of Colorado from outside the State of Colorado. The relocation date is the date the subject engine begins to operate.

I.D.5.a.(ii) Exemptions.

- I.D.5.a.(ii)(A) Engines that burn less than 100 MMBtu per year of natural gas on a rolling-12-month basis are not subject to Sections I.D.5.b., I.D.5.d., I.D.5.e., I.D.5.f.(i)-(iii) and (v)-(vi), or I.D.5.g.
- I.D.5.a.(ii)(B) Non-road engines, as defined in Regulation Number 3, Part A, Section I.B.31 are not subject to this Section I.D.5.
- I.D.5.a.(ii)(C) Any emergency power generator exempt from APEN or construction permit requirements pursuant to Regulation Number 3, Parts A or B are not subject to this Section I.D.5.
- I.D.5.a.(ii)(D) Emergency power generators that operate less than 250 hours per year on a rolling-12-month basis are not subject to Sections I.D.5.b., I.D.5.d., I.D.5.e., I.D.5.f.(i)-(iii) and (v)-(vi), or I.D.5.g.

I.D.5.b. Emission Standards for Engines Subject to Section I.D.5.a.

- I.D.5.b.(i) The owner or operator of any stationary natural gas fired reciprocating internal combustion engine that is placed in service, modified, or relocated after November 14, 2020, must comply with the emission standards in Table 2 upon placement in service, modification, or relocation.

- I.D.5.b.(ii) The owner or operator of any stationary natural gas fired reciprocating internal combustion engine not subject to Section I.D.5.b.(i) must comply with the emission standards in Table 2 in accordance with the timing set forth Section I.D.5.b.(v).

TABLE 2			
Engine Type	Emission Standards (g/hp-hr)		
	NOx	CO	VOC
4-Stroke Lean Burn engines in service on or before November 14, 2020, (unless subject to a more stringent emission standard under Section I.D.3.b, above)	1.2	2.0	0.7
<u>Rich Burn engines in service on or before November 14, 2020</u>	0.8	2.0	0.7
<u>4-Stroke Lean Burn engines placed in service, modified, or relocated after November 14, 2020</u>	0.7	2.0	0.7
<u>Rich Burn engines placed in service, modified, or relocated after November 14, 2020</u>	0.5	2.0	0.7
<u>2-Stroke Lean Burn engines</u>	3.0	2.0	0.7

- I.D.5.b.(iii) By May 1, 2021, owners and operators of an engine placed in service on or before November 14, 2020, that is subject to an emission standard in Table 2 must submit a notification to the Division containing the following information:

- I.D.5.b.(iii)(A) The list of engines subject to an emission standard in Table 2, including AIRS number, location (inside or outside the 8-Hour Ozone Control Area and facility name), historical annual hours of operation averaged over calendar years 2017, 2018, and 2019, manufacturer model, serial number, horsepower, and engine configuration. The notification must also identify or calculate the g/hp-hr limit in an existing permit and the g/hp-hr at which the engine is operating on or before November 14, 2020, if different than the permitted rate. Engine configuration (e.g. rich burn or lean burn) for purposes of the emission standards in Table 2 is determined by the characterization on the engine's permit or APEN as of May 1, 2021. If the engine configuration is not identified in a permit or APEN, the owner or operator must submit an APEN with the current configuration information as determined by the owner or operator by May 1, 2021 to the Division.

- I.D.5.b.(iii)(B) An identification of the applicable standard and a declaration as to whether each subject engine meets the applicable standard as of May 1, 2021. If an engine will meet the applicable standard through a permit modification only, as described in Section I.D.5.b.(iv)(A), below, the declaration should note the date of permit modification submittal.
- I.D.5.b.(iii)(C) For all engines that do not meet the applicable emission standard as of May 1, 2021 or that cannot comply through a permit modification described in Section I.D.5.b.(iv)(A), below, a declaration of what action the owner or operator will take to meet the standard (e.g., control equipment installation, retrofit, replacement, electrification, shut-down). This declaration can be amended at any time prior to the applicable compliance date for that engine.
- I.D.5.b.(iii)(D) The compliance deadline for each engine under Sections I.D.5.b.(i) or I.D.5.b.(v). An owner or operator may change a proposed compliance deadline for an engine subject to Section I.D.5.b.(v)(B) prior to that engine's compliance deadline, only after submittal of an updated notification to the Division that includes the updated compliance date and a demonstration that the requirements of Table 3 are met.
- I.D.5.b.(iii)(E) Owners or operators that submit an Alternative Company-Wide Compliance Plan under Section I.D.5.c. are not subject to this Section I.D.5.b.(iii) for the emission standards in Table 2 for the engines covered by the Alternative Company-Wide Compliance Plan.

I.D.5.b.(iv) Permit Modification.

- I.D.5.b.(iv)(A) An engine in service on or before November 14, 2020 that requires only a modification of an existing permit to meet the emission standards in this Section I.D.5.b. must submit a complete permit application containing the necessary limitations no later than May 1, 2021.
- I.D.5.b.(iv)(B) For any engine not subject to Section I.D.5.b.(iv)(A), owners and operators must modify existing permits to reflect the emission standards or other operating conditions necessary to achieve compliance with Table 2. Complete permit applications must be submitted to the Division at least 365 days prior to the date established in Section I.D.5.b.(iii)(D) above for that engine.

I.D.5.b.(v) Compliance Deadlines for engines subject to Section I.D.5.b.(ii).

I.D.5.b.(v)(A) Engines that comply with the emission standards on or before November 14, 2020, or are subject to Section I.D.5.b.(iv)(A) must meet the emission standards in Table 2 by May 1, 2022.

I.D.5.b.(v)(B) Engines not subject to Section I.D.5.b.(v)(A) must meet the emission standards in Table 2 in accordance with the timing set forth in Table 3.

TABLE 3					
Location of Subject Engines by Owner or Operator	Compliance Deadlines				
	May 1, 2022	May 1, 2023	May 1, 2024	May 1, 2025	May 1, 2026
	Percent (%) of engines that must comply with Table 2 limits				
Inside, or inside and outside, the 8-Hour Ozone Control Area	At least 34% of engines inside the 8-Hour Ozone Control Area	At least 67% of engines inside the 8-Hour Ozone Control Area; and at least 25% of engines outside the 8-Hour Ozone Control Area	100% of engines in the 8-Hour Ozone Control Area; and at least 50% of engines outside the 8-Hour Ozone Control Area	At least 75% of engines outside the 8-Hour Ozone Control Area	100% of all engines
Outside the 8-Hour Ozone Control Area only	At least 20%	At least 40%	At least 60%	At least 80%	100%

I.D.5.b.(vi) If an owner or operator replaces an engine subject to an emission standard under this Section I.D.5.b. with a different stationary natural gas fired reciprocating internal combustion engine, the replacement engine must:

I.D.5.b.(vi)(A) if being placed under an alternative operating scenario pursuant to an existing Division issued permit, meet the same emission standard as the engine being replaced; or

I.D.5.b.(vi)(B) if the owner or operator of an engine chooses to comply via an Alternative Company-Wide Compliance Plan under Section I.D.5.c., meet an emission standard at least as stringent as the engine being replaced as provided for in the applicable Alternative Company-Wide Compliance Plan.

I.D.5.c. Alternative Company-Wide Compliance Plan.

I.D.5.c.(i) Owners and operators with five or more engines that are subject to Section I.D.5.b.(v)(B) may comply with the NOx requirements of Section I.D.5.b. through an Alternative Company-Wide Compliance Plan. Any owner or operator electing to develop an Alternative Company-Wide Compliance Plan must submit a Compliance Plan that meets the requirements of Section I.D.5.c.(ii) on or before May 1, 2021.

I.D.5.c.(i)(A) Only engines subject to an emission standard in Table 2 and that were placed in service on or before the November 14, 2020, can be included in an Alternative Company-Wide Compliance Plan submitted pursuant to this Section I.D.5.c.

I.D.5.c.(i)(B) Engines in an Alternative Company-Wide Compliance Plan must still meet the VOC and CO standards in Table 2 by the deadline established for that engine pursuant to Table 4.

I.D.5.c.(i)(C) Owners and operators owned by the same parent company may collectively submit a Compliance Plan in accordance with this Section I.D.5.c. However, the Compliance Plan must be signed and certified by a responsible official from each owner or operator with engines subject to the Compliance Plan acknowledging that each owner and operator is jointly and severally liable for compliance with the Compliance Plan and the provisions of this Section I.D.5.c. No engine may be included in multiple Alternative Company-Wide Compliance Plans.

I.D.5.c.(ii) The Compliance Plan must be submitted on the Division-approved form and include all of the following elements:

I.D.5.c.(ii)(A) A list of all of the engines that will rely on this Section I.D.5.c. to comply with the standards established in Section I.D.5.b. Each engine must be identified by AIRS number, location (inside or outside the 8-Hour Ozone Control Area and facility name), horsepower, manufacturer, model and serial number, historical annual operating hours (averaged over 2017, 2018, and 2019), and engine configuration.

I.D.5.c.(ii)(B) For each engine included in the Alternative Company-Wide Compliance Plan:

I.D.5.c.(ii)(B)(1) Identification of the most stringent NOx emission standard (in g/hp-hr or converted to g/hp-hr, if not expressed as such in the applicable permit) and operating conditions applicable to the engine under any rule or permit condition in effect on or before November 14, 2020.

- I.D.5.c.(ii)(B)(2) Identification of the g/hp-hr at which the engine is operating on or before November 14, 2020, if different than the rate identified in Section I.D.5.c.(ii)(B)(1), above.
- I.D.5.c.(ii)(B)(3) The emission standards (in g/hp-hr) and any operating conditions with which each engine will comply under the Alternate Company-Wide Compliance Plan, including any intended shut-downs, including any modifications or changes made to comply with the VOC or CO standards in Table 2.
- I.D.5.c.(ii)(B)(4) The date by which each engine will meet the emission standards or other operating conditions identified in Section I.D.5.c.(ii)(B)(3) above, consistent with Table 4.
- I.D.5.c.(ii)(B)(5) The maximum allowable NOx emissions (in tons/year) based on limits applicable on or before November 14, 2020, as identified in Section I.D.5.c.(ii)(B)(1).
- I.D.5.c.(ii)(B)(6) The historic NOx emissions (in tons/year) averaged over calendar years 2017, 2018 and 2019, based on actual operating hours and permitted emission standards.
- I.D.5.c.(ii)(B)(7) The NOx emissions that would be allowed on an annual basis (in tons/year) assuming the engine was complying with the emission standards established in Table 2.
- I.D.5.c.(ii)(B)(8) Each engine's allowable NOx emissions (in tons/year) when operated in accordance with limitations identified in Section I.D.5.c.(ii)(B)(3), above, including any increase in NOx emissions that result from modifications or changes made to comply with the VOC or CO standards in Table 2.
- I.D.5.c.(ii)(C) The total allowable NOx emissions (in tons/year) calculated for all engines in the Alternative Company-Wide Compliance Plan, as specified in Section I.D.5.c.(ii)(B)(5).
- I.D.5.c.(ii)(D) The total NOx emissions (in tons/year) calculated for all engines in the Alternative Company-Wide Compliance Plan, as specified in Section I.D.5.c.(ii)(B)(6).
- I.D.5.c.(ii)(E) The total NOx emissions calculated for all engines included in the Alternate Company-Wide Compliance Plan assuming all engines were complying with the emission standards established in Table 2, as specified in Section I.D.5.c.(ii)(B)(7).

I.D.5.c.(ii)(F) The total allowable NOx emissions (in tons/year) calculated for all engines included in the Alternate Company-Wide Compliance Plan, as specified in Section I.D.5.c.(ii)(B)(8) above.

I.D.5.c.(ii)(G) A calculation of:

I.D.5.c.(ii)(G)(1) The difference between Section I.D.5.c.(ii)(C) and Section I.D.5.c.(ii)(F). This difference is called the "Plan Emission Reductions".

I.D.5.c.(ii)(G)(2) The difference between total historic NOx emissions as calculated in Section I.D.5.c.(ii)(D) and the total allowable NOx emissions (in tons/year) for all engines included in the Alternate Company-Wide Compliance Plan assuming all engines were complying with Table 2, as specified in Section I.D.5.c.(ii)(E).

I.D.5.c.(ii)(G)(3) The difference between total historic NOx emissions as calculated in Section I.D.5.c.(ii)(D) and the total allowable NOx emissions (in tons/year) for all engines included in the Alternate Company-Wide Compliance Plan, as specified in Section I.D.5.c.(ii)(F).

I.D.5.c.(ii)(H) A demonstration that:

I.D.5.c.(ii)(H)(1) The total NOx emissions allowed under the Alternative Company-Wide Compliance Plan (Section I.D.5.c.(ii)(F)) are less than or equal to the total NOx emissions that would be allowed under Table 2 (Section I.D.5.c.(ii)(E)).

I.D.5.c.(ii)(H)(2) The reductions from emissions achieved by the Alternative Company-Wide Compliance Plan are greater than or equal to the reductions from actual emissions achieved by Table 2 (i.e. that the figure calculated in Section I.D.5.c.(ii)(G)(3) is greater than or equal to the figure calculated in Section I.D.5.c.(ii)(G)(2)).

I.D.5.c.(ii)(I) A certification by the owner or operator that based on information and belief formed after reasonable inquiry, the statements and information in the Compliance Plan are true, accurate, and complete.

I.D.5.c.(iii) Any owner or operator utilizing this Alternative Company-Wide Compliance Plan must meet the emission standards for NOx, CO and VOC as identified in I.D.5.c.(ii)(B)(3) by the compliance deadlines listed in Table 4, below.

- I.D.5.c.(iv) Owners and operators must modify existing permits to reflect the emission standards or other operating conditions identified in the Compliance Plan (Section I.D.5.c.(ii)(B)(3)) for that engine. Permit applications must be submitted to the Division at least 365 days prior to the date established in Section I.D.5.c.(ii)(B)(4) above for that engine.
- I.D.5.c.(v) Compliance Plan Updates. By May 1st of each year (beginning in 2022) and continuing through and including the final year of a Compliance Plan, an owner or operator must submit an update to the Compliance Plan with the following information:
- I.D.5.c.(v)(A) For each engine, any change in location and any action taken under the Compliance Plan (e.g., permit modification applied for, engine retrofit completed, engine taken offline) and the date;
 - I.D.5.c.(v)(B) A calculation of the percentage of Plan Emission Reductions achieved as of the date of submittal of the update (in each compliance period and cumulatively);
 - I.D.5.c.(v)(C) Any changes made to the Compliance Plan (e.g. change in compliance date for an engine). No change to the compliance date for an engine can be made after the date established in the Compliance Plan for that engine.;
 - I.D.5.c.(v)(D) If ownership or operation of an engine in the Compliance Plan for which emission reductions were included in the calculation of Plan Emission Reductions was sold or transferred in the previous year, an identification of how the owner or operator will achieve the portion of Plan Emission Reductions attributed to that engine under the Compliance Plan (the difference between Section I.D.5.c.(ii)(B)(5) and (8)).
 - I.D.5.c.(v)(E) A certification by the owner or operator that based on information and belief formed after reasonable inquiry, the statements and information in the update are true, accurate, and complete.
- I.D.5.c.(vi) Nothing in this section I.D.5.c exempts an engine that is part of an Alternative Company-Wide Compliance Plan from compliance with the performance testing, monitoring, recordkeeping or reporting requirements of this Section I.D.5.

TABLE 4					
Location of Subject Engines covered by the Alternative Company-Wide Compliance Plan	Compliance Deadlines				
	May 1, 2022	May 1, 2023	May 1, 2024	May 1, 2025	May 1, 2026
	Percent (%) of Plan Emission Reductions Achieved				
Inside, or inside and outside, the 8-Hour Ozone Control Area	At least 50% of Plan Emission Reductions from engines inside the 8-Hour Ozone Control Area	At least 75% of Plan Emission Reductions from engines inside the 8-Hour Ozone Control Area; and at least 25% of Plan Emission Reductions from engines outside the 8-Hour Ozone Control Area	100% of Plan Emission Reductions from engines inside the 8-Hour Ozone Control Area; and at least 50% of Plan Emission Reductions from engines outside the 8-Hour Ozone Control Area	At least 75% of Plan Emission Reductions from engines outside the 8-Hour Ozone Control Area	100% of Plan Emission Reductions
Outside the 8-Hour Ozone Control Area only	At least 20%	At least 40%	At least 60%	At least 80%	100%

I.D.5.d. Performance Testing

I.D.5.d.(i) Engines subject to this Section I.D.5. must conduct a performance test consistent with the requirements of this Section I.D.5.d.

I.D.5.d.(i)(A) The owner or operator of an engine subject to Section I.D.5.b.(ii) must conduct a performance test for NO_x, CO, and O₂ by May 1, 2021.

I.D.5.d.(i)(B) The owner or operator of an engine placed in service, modified, relocated or replaced after May 1, 2021 must conduct a performance test within 12 months of the date the engine is placed in service, modified, relocated or replaced.

I.D.5.d.(i)(C) The following engines are exempt from the requirements of this Section I.D.5.d.

I.D.5.d.(i)(C)(1) Engines subject to the performance testing requirements of 40 C.F.R. Part 60, Subpart JJJJ (July 1, 2019).

I.D.5.d.(i)(C)(2) Engines subject to at least semi-annual portable analyzer testing or ongoing performance testing in a permit issued on or before November 14, 2020.

I.D.5.d.(i)(D) A performance test conducted in accordance with 40 C.F.R. §60.4244 (July 1, 2019) between January 1, 2020 and May 1, 2021 will satisfy the initial performance testing requirements in Section I.D.5.d.(i)(A).

I.D.5.d.(ii) Performance tests must be conducted in accordance with the applicable reference test methods of 40 C.F.R. Part 60, Appendix A (DATE), and a test protocol submitted to the Division for review at least thirty (30) days prior to testing and in accordance with AQCC Common Provisions Regulation Section II.C.

I.D.5.d.(iii) Tuning of an engine prior to the performance test required by this Section I.D.5.d is not a violation of this rule. However, readjustment of an engine set point following the performance test that would negatively impact the performance of the engine (i.e. result in increased emissions above applicable permit limits) is a violation of this rule.

I.D.5.e. Monitoring. Except as provided in Section I.D.5.a.(ii), owners or operators of an engine subject to Section I.D.5.a must:

I.D.5.e.(i) Beginning on May 1, 2022, conduct semi-annual portable analyzer monitoring for NOx, CO, and O2. At least one calendar month must separate the semi-annual tests.

I.D.5.e.(i)(A) If the engine is operated for less than 200 hrs in any semi-annual period, then the portable analyzer monitoring need not occur during that semi-annual period (i.e. the engine does not need to be started for the sole purpose of portable monitoring).

I.D.5.e.(i)(B) All portable analyzer testing required by this section must be conducted using the Division's Portable Analyzer Monitoring Protocol (version: March 2006).

I.D.5.e.(i)(C) Tuning of an engine prior to semi-annual monitoring events required by this Section I.D.5.e.(i) is not a violation of this rule. However, readjustment of an engine set point following the monitoring event that would negatively impact the performance (i.e. result in increased emissions above applicable permit limits) of the engine is a violation of this rule.

I.D.5.e.(i)(D) A performance test conducted pursuant to Section I.D.5.d., 40 C.F.R. Part 60, JJJJ, or a permit requirement may take the place of the next required semi-annual portable analyzer test required by this section.

- I.D.5.e.(i)(E) An engine subject to at least semi-annual portable analyzer testing requirements in an existing permit issued by the Division can comply with this Section I.D.5.e.(i) by complying with the testing requirements in the permit.
- I.D.5.e.(ii) Beginning May 1, 2021, if a catalyst is used to reduce emissions:
 - I.D.5.e.(ii)(A) Monitor the inlet temperature to the catalyst daily and conduct maintenance if the temperature is not within applicable limits.
 - I.D.5.e.(ii)(B) Measure the pressure drop across the catalyst monthly and conduct maintenance if the pressure drop is greater than 2 inches outside the baseline value established after each semi-annual portable analyzer monitoring.
 - I.D.5.e.(ii)(C) Engines that are subject to catalyst temperatures and catalyst pressure drop monitoring requirements in an existing permit issued by the Division or 40 C.F.R. Part 63, Subpart ZZZZ (July 1, 2019) satisfy the monitoring requirements of this Section I.D.5.e.(ii).
- I.D.5.e.(iii) Beginning May 1, 2021 or the date the engine is placed in service, modified, relocated or replaced (if later), install (if not already) and operate an hour meter or Division approved alternate method to continuously track the hours of operation of the subject engine.
- I.D.5.e.(iv) Conduct the following inspections and adjustments at least annually, unless otherwise specified below, beginning in 2022
 - I.D.5.e.(iv)(A) Change oil and filters as necessary; and,
 - I.D.5.e.(iv)(B) Inspect air cleaners, fuel filters, hoses, and belts and clean or replace as necessary; and,
 - I.D.5.e.(iv)(C) Inspect spark plugs and replace as necessary; or,
 - I.D.5.e.(iv)(D) Conduct a combustion process adjustment according to the manufacturer recommended procedures and schedule. Alternatively, the owner or operator may rely on a combustion process adjustment conducted in accordance with requirements and schedules of a New Source Performance Standard in 40 CFR Part 60 (July 1, 2019) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (July 1, 2019) conducted during the same annual period to satisfy the annual combustion process adjustment requirement of this Section I.D.5.c.(iv)(D) for that 12-month period.
- I.D.5.f. Recordkeeping. The following records must be kept for a period of five years and made available to the Division upon request.

- I.D.5.f.(i) Records of performance tests conducted pursuant to Section I.D.5.d, including I.D.5.d.(i)(D), including the date, engine settings on the date of the test, and documentation of the methods and results of the testing.
- I.D.5.f.(ii) Records of semi-annual portable analyzer monitoring, including the date, engine settings on the date of the monitoring, and documentation of the results of the monitoring. These records must include any demonstration that no semi-annual portable analyzer monitoring was required as provided under Section I.D.5.e.(i)(D) or I.D.5.e.(i)(E), if applicable.
- I.D.5.f.(iii) Records of catalyst monitoring required by Section I.D.5.e.(ii) and any actions taken to address monitored values outside the temperature or pressure drop parameters, including the date and a description of actions taken.
- I.D.5.f.(iv) If claiming an exemption under Section I.D.5.a.(ii), records demonstrating that fuel combustion was less than 100 MMBtu per year or hours of operation are less than 250 hours per year.
- I.D.5.f.(v) Hours of operation as recorded by the hour meter or alternative device approved by the Division continuously tracking hours as required by Section I.D.5.e.(iii), at least on a calendar month basis.
- I.D.5.f.(vi) Records of tuning, adjustments, or other combustion process adjustments required under Section I.D.5.e.(iv), including:
 - I.D.5.f.(vi)(A) The date of the adjustment.
 - I.D.5.f.(vi)(B) A description of any corrective action taken.
 - I.D.5.f.(vi)(C) If the owner or operator conducts the combustion process adjustment according to the manufacturer recommended procedures and schedule and the manufacturer specifies a combustion process adjustment on an operation time schedule, the hours of operation since the last combustion process adjustment and the procedures followed. The owner or operator must retain documentation of any relied upon manufacturer recommended procedures, specifications, and maintenance schedule for five years after the owner or operator ceases to rely upon it.
 - I.D.5.f.(vi)(D) If the owner or operator conducts the combustion process adjustment according to a New Source Performance Standard or National Emission Standard for Hazardous Air Pollutants, what standard applied and what procedures were followed.

I.D.5.g. Reporting. Beginning on the date specified below and by May 1 of each year thereafter, the owner or operator of each engine subject to this Section I.D.5. must submit the following information covering the preceding calendar year:

- I.D.5.g.(i) Beginning May 1, 2021, a statement of the status of performance testing required under Section I.D.5.d, and the date and results of that testing;
- II.D.5.g.(ii) Beginning May 1, 2022, an identification of any engines placed in service, modified, relocated, or replaced, including AIRS number, serial number, location, engine configuration, and a certification as to whether the emission standards in Table 2 are met;
- I.D.5.g.(iii) Beginning May 1, 2022, the date on which the monitoring required by Sections I.D.5.e.(iv) was performed;
- I.D.5.g.(iv) Beginning May 1, 2023, the date that all required semi-annual portable analyzer testing was performed under Section I.D.5.e.(i), and the results of that testing.

II. Control of Emissions from Stationary and Portable Combustion Equipment in the 8-Hour Ozone Control Area

II.A. Requirements for major sources of NOx

II.A.1. Applicability.

II.A.1.a. Except as provided in Section II.A.2., the requirements of this Section II. apply to owners and operators of any stationary combustion equipment that existed at a major source of NOx (greater than or equal to 100 tpy NOx) as of June 3, 2016, located in the 8-Hour Ozone Control Area.

II.A.1.b. Except as provided in Section II.A.2., the requirements of Section II. apply to owners and operators of any stationary combustion equipment that existed at a major source of NOx (greater than or equal to 50 tpy NOx) as of January 27, 2020, located in the 8-Hour Ozone Control Area, that is not already subject as provided under Section II.A.1.a.

II.A.2. Exemptions. The following stationary combustion equipment are exempt from the emission limitation requirements of Section II.A.4., the compliance demonstration requirements in Section II.A.5., and the related recordkeeping and reporting requirements of Sections II.A.7.a-e. and II.A.8, but these sources must maintain any and all records necessary to demonstrate that an exemption applies. These records must be maintained for a minimum of five years and made available to the Division upon request. Qualifying for an exemption in this section does not preclude the combustion process adjustment requirements of Section II.A.6., when required by II.A.6.a.

Once stationary combustion equipment no longer qualifies for any exemption, the owner or operator must comply with the applicable requirements of this Section II.A. as expeditiously as practicable but no later than 36 months after any exemption no longer applies. Additionally, once stationary combustion equipment that is not equipped with CEMS or CERMS no longer qualifies for any exemption, the owner or operator must conduct a performance test using EPA test methods within 180 days and notify the Division of the results and whether emission controls will be required to comply with the emission limitations of Section II.A.4.

II.A.2.a. Any stationary combustion equipment whose utilization is less than:

- II.A.2.a.(i) 20% of its capacity factor on an annual average basis over a 3-year rolling period for boilers; or

II.A.2.a.(ii) 10% of its capacity factor on an annual average basis over a 3-year rolling period for stationary combustion turbines and compression ignition reciprocating internal combustion engines.

II.A.2.b. An engine testing operation or process line.

II.A.2.c. Any gaseous fuel fired stationary combustion equipment used to control VOC emissions from a commercial or industrial process.

II.A.2.d. Any stationary combustion equipment with total uncontrolled actual emissions less than 5 tpy NOx on a calendar year basis.

II.A.2.e. Any natural gas-fired reciprocating internal combustion engines subject to a work practice or emission control requirement contained in this Regulation 7, Section I.A. or B.

II.A.2.f. Any stationary combustion equipment subject to a federally enforceable work practice or emission control requirement contained in this Regulation 7, Section III.A.-B. or Regulation 3, Part F.

II.A.3. Definitions

II.A.3.a. "Affected unit" means any stationary combustion equipment that is subject to or becomes subject to an emission limitation in Section II.A.4.

II.A.3.b. "Boiler" means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water.

II.A.3.c. "Capacity factor" means the ratio of the amount of fuel burned by an emissions unit in a calendar year to the amount of fuel it could have burned if it had operated at the designed heat input rating for 8,760 hours during the calendar year. Alternatively, for electric generating units, capacity factor can mean the ratio of the unit's actual annual electric output (expressed in MWe/hr) to the electric output the unit could have achieved if it operated at its nameplate capacity (or maximum observed hourly gross load (expressed in MWe/hr) if greater than the nameplate capacity) for 8,760 hours during the calendar year.

II.A.3.d. "Ceramic kiln" means equipment used for the curing or firing of ceramic products or glaze on ceramic products. A kiln may operate continuously or by batch process.

II.A.3.e. "Continuous emission monitoring system" ("CEMS") or "Continuous emission rate monitoring system" ("CERMS") means the total equipment required to sample, condition (if applicable), analyze, and provide a written record of such emissions and/or emission rates, expressed on a continuous basis in terms of an applicable emission limitation. Such equipment includes, but is not limited to, sample collection and calibration interfaces, pollutant analyzers, a diluent analyzer (oxygen or carbon dioxide), stack gas volumetric flow monitors (if appropriate for CERMS), and data recording and storage devices.

- II.A.3.f. “Compression ignition reciprocating internal combustion engine (RICE)” means a type of stationary RICE that is liquid fuel-fired and not ignited with a spark plug or other sparking device.
- II.A.3.g. “Digester gas” means any gaseous byproduct of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and carbon dioxide.
- II.A.3.h. “Duct burner” means a device that combusts fuel and is placed in the exhaust duct from another source (e.g., stationary combustion turbine, internal combustion engine, or kiln) to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.
- II.A.3.i. “Dryer” means a device that is used to reduce or evaporate moisture content or remove organic contaminants.
- II.A.3.j. “Furnace” means an enclosed device that is an integral component of a manufacturing process and that uses thermal treatment to accomplish recovery of materials or energy.
- II.A.3.k. “Gaseous fuel” means natural gas, landfill gas, refinery fuel gas, digester gas, methane, ethane, propane, butane, or any gas stored as a liquid at high pressure such as liquefied petroleum gas.
- II.A.3.l. “Glass melting furnace” means an emissions unit comprising a refractory vessel in which raw materials are charged, melted at high temperature, refined, and conditioned to produce molten glass.
- II.A.3.m. “Kiln” means the equipment used to remove combined (chemically bound) water and/or gases from mineral material through direct or indirect heating.
- II.A.3.n. “Lightweight aggregate” means the expanded, porous product from heating shales, clays, slates, slags, or other natural materials in a kiln.
- II.A.3.o. “Liquid fuel” means any fuel which is a liquid at standard conditions including but not limited to distillate oils, kerosene and jet fuel. Liquefied gaseous fuels are not liquid fuels.
- II.A.3.p. “Process heater” means an enclosed device using controlled flame and a primary purpose to transfer heat directly to a process material or to a heat transfer material for use in a process.
- II.A.3.q. “Reciprocating internal combustion engine” means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not used to propel a motor vehicle or a vehicle used solely for competition.

- II.A.3.r. “Stationary combustion equipment” means an emissions unit that combusts solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use. Stationary combustion equipment includes, but is not limited to, boilers, duct burners, engines, glass melting furnaces, kilns, process heaters, stationary combustion turbines, dryers, furnaces, and ceramic kilns.
- II.A.3.s. “Stationary combustion turbine” means a non-mobile, enclosed fossil or other fuel-fired device that is comprised of a compressor, a combustor and a turbine, and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine. Stationary combustion turbines can be simple cycle or combined cycle and they may or may not include a duct burner.

II.A.4. Emission limitations.

By October 1, 2021, no owner or operator of stationary combustion equipment specified in Section II.A.1.a. may cause, allow, or permit NO_x to be emitted in excess of the following emission limitations. When demonstrating compliance using continuous emissions monitoring pursuant to Section II.A.5.c.(i), the following emission limitations are on a 30-day rolling average basis, unless otherwise specified.

By July 20, 2021, no owner or operator of stationary combustion equipment specified in Section II.A.1.b. may cause, allow, or permit NO_x to be emitted in excess of the following emission limitations. When demonstrating compliance using continuous emissions monitoring pursuant to Section II.A.5.c.(i), the following emission limitations are on a 30-day rolling average basis, unless otherwise specified.

II.A.4.a. Boilers.

- II.A.4.a.(i) For a gaseous fuel-fired boiler with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, 0.2 lb/MMBtu of heat input or less than 165 parts per million dry volume corrected to 3% oxygen.
- II.A.4.a.(ii) For a liquid fuel-fired boiler with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, 0.2 lb/MMBtu of heat input or less than 165 parts per million dry volume corrected to 3% oxygen.
- II.A.4.a.(iii) For a liquid or gaseous fuel-fired boiler at a major source of NO_x (greater than or equal to 50 tpy NO_x as of January 27, 2020) with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, 0.2 lb/MMBtu of heat input or less than 165 parts per million dry volume corrected to 3% oxygen.
- II.A.4.a.(iv) For a liquid or gaseous fuel-fired boiler at a major source of NO_x (greater than or equal to 50 tpy NO_x as of January 27, 2020) with a maximum design heat input capacity equal to or greater than 50 MMBtu/hr but less than 100 MMBtu/hr, 0.1 lb/MMBtu of heat input or less than 83 parts per million dry volume corrected to 3% oxygen.

- II.A.4.a.(v) Boilers subject to the categorical limits in Section II.A.4.a.(i) through (iv) or boilers with a maximum design heat input capacity less than 100 MMBtu/hr must comply with the combustion process adjustment requirements contained in Section II.A.6. while burning gaseous fuel, liquid fuel, or any combination thereof, when required by Section II.A.6.a.

II.A.4.b. Stationary combustion turbines.

- II.A.4.b.(i) Stationary combustion turbines with a maximum design heat input capacity equal to or greater than 10 MMBtu/hr and which commenced construction on or before February 18, 2005 must comply with the following NOx emission limits in Table 1.

Table 1 – NOx limits for stationary combustion turbines constructed on or before February 18, 2005		
Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NOx emission standard
Turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O ₂ or 54 ng/J of useful output (0.43 lb/MWh)
Turbine firing fuels other than natural gas	> 850 MMBtu/h	42 ppm at 15 percent O ₂ or 160 ng/J of useful output (1.3 lb/MWh).
Turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O ₂ or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O ₂ or 250 ng/J of useful output (2.0 lb/MWh).
Turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O ₂ or 590 ng/J of useful output (4.7 lb/MWh).
Turbines operating at less than 75 percent of peak load, turbines operating at temperatures less than 0 °F	≤ 30 MW output	150 ppm at 15 percent O ₂ or 1,100 ng/J of useful output (8.7 lb/MWh).
Turbines operating at less than 75 percent of peak load, turbines operating at temperatures less than 0 °F	> 30 MW output	96 ppm at 15 percent O ₂ or 590 ng/J of useful output (4.7 lb/MWh).
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O ₂ or 110 ng/J of useful output (0.86 lb/MWh).

- II.A.4.b.(i)(A) For units with heat recovery and CEMS, determine compliance on a 30-day rolling average.
- II.A.4.b.(i)(B) For simple cycle turbines with CEMS, determine compliance on a 4-hour rolling average.
- II.A.4.b.(i)(C) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.
- II.A.4.b.(i)(D) Emissions exceeding the NO_x emission limits in Section II.A.4.b.(i) at any time, including during times of startup, shutdown, malfunction, fuel switching, tuning, and testing must be reported as specified in Section II.A.8.a.(i).
- II.A.4.b.(ii) Stationary combustion turbines with a maximum design heat input capacity equal to or greater than 10 MMBtu/hr and which commenced construction, modification or reconstruction after February 18, 2005 must comply with the applicable NO_x emission limits in 40 CFR Part 60, Subpart KKKK (July 1, 2017).
- II.A.4.b.(iii) Stationary combustion turbines subject to the categorical limits in Section II.A.4.b.(i) or (ii) above and stationary combustion turbines with a maximum design heat input capacity less than 10 MMBtu/hr must comply with the combustion process adjustment requirements contained in Section II.A.6. while burning gaseous fuel, liquid fuel, or any combination thereof, when required by Section II.A.6.a.
- II.A.4.b.(iv) Stationary combustion turbines, air pollution control equipment, and monitoring equipment must be operated in a manner consistent with good air pollution control practices for minimizing emissions at all times.
- II.A.4.c. Lightweight aggregate kilns.
 - II.A.4.c.(i) For lightweight aggregate kilns with a maximum design heat input capacity equal to or greater than 50 MMBtu/hr, 56.6 pounds of NO_x per hour.
- II.A.4.d. Glass melting furnaces.

II.A.4.d.(i) For, glass melting furnaces, 1.2 pounds of NO_x per ton of glass pulled. However, days in which a glass melting furnace is operated at less than 35% of maximum designed production may be excluded from the 30-day rolling average for purposes of demonstrating compliance with this Section II.A.4.d.(i). During each day excluded from the 30-day rolling average, NO_x emissions must be measured continuously in accordance with the applicable monitoring requirements of Section II.A.5, and the furnace must be operated in accordance with good air pollution control practices.

II.A.4.e. Compression ignition RICE.

II.A.4.e.(i) For a compression ignition RICE with a maximum design power output equal to or greater than 500 horsepower, 9 grams per brake horsepower-hour.

II.A.4.e.(ii) Compression ignition RICE subject to the emission limit in Section II.A.4.e.(i) above and compression ignition RICE with a maximum design power output less than 500 horsepower must comply with the combustion process adjustment requirements contained in Section II.A.6.

II.A.4.f. Landfill gas or biogas gas fired RICE.

II.A.4.f.(i) For landfill gas or biogas fired RICE with a maximum design power output equal to or greater than 500 horsepower, 2 grams per brake horsepower-hour

II.A.5. Compliance demonstration.

II.A.5.a. By October 1, 2021, for stationary combustion equipment that existed at a major source of NO_x (greater than or equal to 100 tpy NO_x) as of June 3, 2016, the owner or operator of an affected unit must determine compliance with the applicable emission limitations contained in Section II.A.4. according to the applicable methods contained in this Section II.A.5.

II.A.5.b. By July 20, 2021, for stationary combustion equipment specified in Section II.A.1.b., the owner or operator of an affected unit must determine compliance with the applicable emission limitations contained in Section II.A.4. according to the applicable methods contained in Sections II.A.5.

II.A.5.c. Emissions monitoring requirements for major source RACT limits

II.A.5.c.(i) Continuous emission monitoring

II.A.5.c.(i)(A) Owners or operators of an affected unit subject to a NO_x emission limit in Section II.A.4.a.(i)-(iii), c. or d. must install, operate and maintain a NO_x CEMS or CERMS to monitor compliance with the applicable emission limit in accordance with this Section II.A.5.c.(i). Owners or operators of affected units' subject to a NO_x emission limit in Section II.A.4.b. or Section II.A.4.e. may install, operate and maintain a NO_x CEMS or CERMS to monitor compliance with the applicable emission limit in accordance with this Section II.A.5.c.(i) in lieu of performance testing pursuant to Section II.A.5.c.(ii).

II.A.5.c.(i)(A)(1) The owner or operator of an affected unit that is subject to or becomes subject to the monitoring requirements of 40 CFR part 75 and 40 CFR part 75, Appendices A to I (July 19, 2018), must use those monitoring methods and specifications for monitoring NO_x emissions for purposes of this Section II.A.5. and for demonstrating compliance with Section II.A.4. The missing data substitution procedures and bias adjustment requirements of 40 CFR Part 75 (July 19, 2018) do not apply for purposes of demonstrating compliance with Section II.A.4. or this Section II.A.5.

II.A.5.c.(i)(A)(2) For an affected unit equipped with a NO_x CEMS or CERMS for purposes of demonstrating compliance with an applicable subpart of 40 CFR Part 60 (July 19, 2018), the owner or operator must use the definition of operating day, data averaging methodology, and data validation requirements of the applicable subpart of 40 CFR Part 60 for purposes of demonstrating compliance with an applicable emission limit in Section II.A.4. The owner or operator must calibrate, maintain, and operate the CEMS or CERMS and validate emissions data according to the applicable requirements of 40 CFR Part 60, Section 60.13 (July 19, 2018), the performance specifications in 40 CFR Part 60, Appendix B (July 19, 2018), and the quality assurance procedures of 40 CFR Part 60, Appendix F (July 19, 2018).

II.A.5.c.(i)(A)(3) For an affected unit that is not equipped with a NO_x CEMS or CERMS for purposes of demonstrating compliance with 40 CFR Part 60 (July 19, 2018) or Part 75 (July 19, 2018), the owner or operator must install, operate, and maintain a NO_x CEMS or CERMS that measures emissions in terms of the applicable emission limitation and must calibrate, maintain, and operate the CEMS or CERMS and validate emissions data according to the applicable provisions of 40 CFR Part 60, Section 60.13 (July 19, 2018), the performance specifications in 40 CFR Part 60, Appendix B (July 19, 2018), and the quality assurance procedures of 40 CFR Part 60, Appendix F (July 19, 2018). The owner or operator must use the following methodology for purposes of demonstrating compliance with an applicable 30-day rolling average emission limit in Section II.A.4.:

II.A.5.c.(i)(A)(3)(a) A unit operating day is a calendar day when any fuel is combusted in the affected unit.

II.A.5.c.(i)(A)(3)(b) 30-day rolling average emission rates must be calculated as the arithmetic average emissions rates determined by the CEMS or CERMS for all hours the affected unit combusted any fuel from the current unit operating day and the prior 29 unit operating days.

II.A.5.c.(i)(A)(4) When an affected unit utilizes a common flue gas stack system with one or more affected units, but no non-affected units, the owner or operator must follow the applicable procedures of 40 CFR Part 75, Appendix F (July 19, 2018) for the determination of all sampling locations and apportionment of emissions to an individual affected unit.

II.A.5.c.(i)(A) Owners or operators of a stationary combustion turbine subject to a NO_x emission limit in Section II.A.4.b. must comply with

II.A.5.c.(i)(A)(1) The applicable monitoring requirements in 40 CFR Part 60, Subpart GG (July 1, 2017) for turbines which commenced construction on or before February 18, 2005.

II.A.5.c.(i)(A)(2) The applicable monitoring requirements in 40 CFR Part 60, Subpart KKKK (July 1, 2017) for turbines which commenced construction after February 18, 2005.

II.A.5.c.(ii) Initial and periodic performance testing

- II.A.5.c.(ii)(A) An owner or operator of a stationary combustion turbine subject to 40 CFR Part 60, Subparts GG or KKKK (July 19, 2018) that has used and continues to use performance testing to demonstrate compliance with either Subpart GG or KKKK (July 19, 2018), as applicable, may use those performance testing procedures to demonstrate continued compliance with an applicable limitation contained in Section II.A.4.b., thereby satisfying the requirements of this section II.A.5.c.(ii).
- II.A.5.c.(ii)(B) Except as otherwise provided for in Section II.A.5.a.(ii)(A), the owner or operator of an affected unit subject to a NO_x emission limitation contained in Sections II.A.4.a.(iv), 4.b., or 4.e. that is not equipped with NO_x CEMS or CERMS, must conduct an initial performance test and subsequent performance tests every 2 years thereafter, according to the following requirements, as applicable, to determine the affected unit's NO_x emission rate for each fuel fired in the affected unit. A performance test is not required for a fuel used only for startup or for a fuel constituting less than 2% of the unit's annual heat input, as determined at the end of each calendar year.
- II.A.5.c.(ii)(B)(1) Initial performance test must include a determination of the capacity load point of the unit's maximum NO_x emissions rate based on one 30-minute test run at each capacity load point for which the unit is operated, other than for startup and shutdown, in the load ranges of 20 to 30%, 45 to 55%, and 70 to 100%. Subsequent performance tests must be performed within the capacity load range determined to result in the maximum NO_x emissions rate.
- II.A.5.c.(ii)(B)(2) Performance tests must determine compliance with Section II.A.4. based on the average of three 60-minute test runs performed at the capacity load determined in II.A.5.c.(ii)(B)(1).
- II.A.5.c.(ii)(C) All performance tests must be conducted in accordance with EPA test methods and a test protocol submitted to the Division for review at least thirty (30) days prior to testing and in accordance with AQCC Common Provisions Regulation Section II.C.

- II.A.5.c.(iii) For affected units' subject to a production-based or output based emission limit contained in Section II.A.4. (e.g. lb of NOx/ton of product), the owner or operator must install, operate, and maintain monitoring equipment for measuring and recording the affected unit's production or output, on an hourly basis, in units consistent with the applicable emission limitation.
- II.A.5.c.(iv) Where measuring fuel use is necessary to calculate an emission rate in the units of the applicable standard, fuel flowmeters must be installed, calibrated, maintained, and operated according to manufacturer's instructions for measuring and recording heat input in terms of the applicable emission limitation. Alternatively, fuel flowmeters that meet the installation, certification, and quality assurance requirements of 40 CFR Part 75, Appendix D (July 19, 2018) are acceptable for demonstrating compliance with this section. The installation of fuel-flowmeters is not required where emissions of NOx in terms of the applicable standard can be calculated in accordance with applicable provisions of EPA Method 19 (July 19, 2018) or where the standard is concentration based (e.g. parts per million dry volume corrected for oxygen).

II.A.6. Combustion process adjustment

II.A.6.a. Applicability

- II.A.6.a.(i) As of January 1, 2017, this Section II.A.6. applies to boilers, duct burners, process heaters, stationary combustion turbines, and stationary reciprocating internal combustion engines with uncontrolled actual emissions of NOx equal to or greater than five (5) tons per year that existed at major sources of NOx (greater than or equal to 100 tpy NOx) as of June 3, 2016.
- II.A.6.a.(ii) As of May 1, 2020, this Section II.A.6. applies to boilers, duct burners, process heaters, stationary combustion turbines, stationary reciprocating internal combustion engines, dryers, furnaces, and ceramic kilns with uncontrolled actual emissions of NOx equal to or greater than five (5) tons per year that existed at major sources of NOx (greater than or equal to 50 tpy NOx) as of January 27, 2020, that is not already subject as provided under Section II.A.6.a.(i).

II.A.6.b. Combustion process adjustment

- II.A.6.b.(i) When burning the fuel that provides the majority of the heat input since the last combustion process adjustment and when operating at a firing rate typical of normal operation, the owner or operator must conduct the following inspections and adjustments of boilers and process heaters, as applicable:
 - II.A.6.b.(i)(A) Inspect the burner and combustion controls and clean or replace components as necessary.

- II.A.6.b.(i)(B) Inspect the flame pattern and adjust the burner or combustion controls as necessary to optimize the flame pattern.
- II.A.6.b.(i)(C) Inspect the system controlling the air-to-fuel ratio and ensure that it is correctly calibrated and functioning properly.
- II.A.6.b.(i)(D) Measure the concentration in the effluent stream of carbon monoxide and nitrogen oxide in ppm, by volume, before and after the adjustments in Sections II.A.6.b.(i)(A) through (C). Measurements may be taken using a portable analyzer.
- II.A.6.b.(ii) The owner or operator of a duct burner must inspect duct burner elements, baffles, support structures, and liners and clean, repair, or replace components as necessary.
- II.A.6.b.(iii) The owner or operator of a stationary combustion turbine must conduct the following inspections and adjustments, as applicable:
 - II.A.6.b.(iii)(A) Inspect turbine inlet systems and align, repair, or replace components as necessary.
 - II.A.6.b.(iii)(B) Inspect the combustion chamber components, combustion liners, transition pieces, and fuel nozzle assemblies and clean, repair, or replace components as necessary.
 - II.A.6.b.(iii)(C) When burning the fuel that provides the majority of the heat input since the last combustion process adjustment and when operating at a firing rate typical of normal operation, confirm proper setting and calibration of the combustion controls.
- II.A.6.b.(iv) The owner or operator of a stationary internal combustion engine must conduct the following inspections and adjustments, as applicable:
 - II.A.6.b.(iv)(A) Change oil and filters as necessary.
 - II.A.6.b.(iv)(B) Inspect air cleaners, fuel filters, hoses, and belts and clean or replace as necessary.
 - II.A.6.b.(iv)(C) Inspect spark plugs and replace as necessary.
- II.A.6.b.(v) The owner or operator of a dryer or furnace must inspect the burner and combustion controls and adjust, clean, and/or replace components as necessary.

- II.A.6.b.(vi) The owner or operator of a ceramic kiln must inspect and maintain the combustion controls and adjust the burners as necessary to ensure a proper air-to-fuel ratio. At units where entry into a piece of process equipment is required to complete the combustion process adjustment, in-kiln inspections and adjustments are required only during planned entries.
- II.A.6.b.(vii) The owner or operator must operate and maintain the boiler, duct burner, process heater, stationary combustion turbine, stationary internal combustion engine, dryer, furnace, or ceramic kiln consistent with manufacturer's specifications, if available, or good engineering and maintenance practices.
- II.A.6.b.(viii) Frequency
- II.A.6.b.(viii)(A) The owner or operator of boilers, duct burners, process heaters, stationary combustion turbines, and stationary reciprocating internal combustion engines with uncontrolled actual emissions of NO_x equal to or greater than five (5) tons per year that existed at major sources of NO_x (greater than or equal to 100 tpy NO_x) as of June 3, 2016, must conduct the initial combustion process adjustment by April 1, 2017. An owner or operator may rely on a combustion process adjustment conducted in accordance with applicable requirements and schedule of a New Source Performance Standard in 40 CFR Part 60 (November 17, 2016) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (November 17, 2016) to satisfy the requirement to conduct an initial combustion process adjustment by April 1, 2017.
- II.A.6.b.(viii)(B) The owner or operator of boilers, duct burners, process heaters, stationary combustion turbines, stationary reciprocating internal combustion engines, dryers, furnaces, and ceramic kilns with uncontrolled actual emissions of NO_x equal to or greater than five (5) tons per year that existed at major sources of NO_x (greater than or equal to 50 tpy NO_x) as of January 27, 2020, must conduct the initial combustion process adjustment by May 1, 2020. An owner or operator may rely on a combustion process adjustment conducted in accordance with applicable requirements and schedule of a New Source Performance Standard in 40 CFR Part 60 (December 19, 2019) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (December 19, 2019) to satisfy the requirement to conduct an initial combustion process adjustment by May 1, 2020.

II.A.6.b.(viii)(C) The owner or operator must conduct subsequent combustion process adjustments at least once every twelve (12) months after the initial combustion adjustment, or on the applicable schedule according to Sections II.A.6.c.(1). or II.A.6.c.(ii).

II.A.6.c. As an alternative to the requirements described in Sections II.A.6.b.(i) through II.A.6.b.(viii):

II.A.6.c.(i) The owner or operator may conduct the combustion process adjustment according to the manufacturer recommended procedures and schedule; or

II.A.6.c.(ii) The owner or operator of combustion equipment that is subject to and required to conduct a periodic tune-up or combustion adjustment by the applicable requirements of a New Source Performance Standard in 40 CFR Part 60 (December 19, 2019) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (December 19, 2019) may conduct tune-ups or adjustments according to the schedule and procedures of the applicable requirements of 40 CFR Part 60 (December 19, 2019) or 40 CFR Part 63 (December 19, 2019).

II.A.7. Recordkeeping. The following records must be kept for a period of five years and made available to the Division upon request:

II.A.7.a. The applicable emission limit and calculated heat input weighted emission limit for stationary combustion equipment demonstrating compliance for multiple fuels.

II.A.7.b. The 30-day rolling average emission rate calculated on a daily basis for sources using CERMS to comply with Section II.A.

II.A.7.c. The type and amount of fuel used.

II.A.7.d. The stationary combustion equipment's annual capacity factor on a calendar year basis.

II.A.7.e. All records generated to comply with the reporting requirements contained in Section II.A.8.

II.A.7.f. For stationary combustion equipment subject to the combustion process adjustment requirements in Section II.A.6., the following recordkeeping requirements apply:

II.A.7.f.(i) The owner or operator must create a record once every calendar year identifying the combustion equipment at the source subject to Section II.A. and including for each combustion equipment:

II.A.7.f.(i)(A) The date of the adjustment;

II.A.7.f.(i)(B) Whether the combustion process adjustment under Sections II.A.6.b.(i) through II.A.6.b.(vi) was followed, and what procedures were performed;

II.A.7.f.(i)(C) Whether a combustion process adjustment under Sections II.A.6.c.(i). and II.A.6.c.(ii). was followed, what procedures were performed, and what New Source Performance or National Emission Standard for Hazardous Air Pollutants applied, if any; and

II.A.7.f.(i)(D) A description of any corrective action taken.

II.A.7.f.(i)(E) If the owner or operator conducts the combustion process adjustment according to the manufacturer recommended procedures and schedule and the manufacturer specifies a combustion process adjustment on an operation time schedule, the hours of operation.

II.A.7.f.(i)(F) If multiple fuels are used, the type of fuel burned and heat input provided by each fuel.

II.A.7.f.(ii) The owner or operator must retain manufacturer recommended procedures, specifications, and maintenance schedule if utilized under Section II.A.6.c.(i). for the life of the equipment.

II.A.7.f.(iii) As an alternative to the requirements described in Section II.A.7.f.(i), the owner or operator may comply with applicable recordkeeping requirements related to combustion process adjustments conducted according to a New Source Performance Standard in 40 CFR Part 60 (November 17, 2016) or National Emission Standard for Hazardous Air Pollutants in 40 CFR Part 63 (November 17, 2016).

II.A.7.g. All sources qualifying for an exemption under Section II.A.2. must maintain all records necessary to demonstrate that an exemption applies.

II.A.8. Reporting

II.A.8.a. For affected units demonstrating compliance with Section II.A.4. using CEMS or CERMS in accordance with Section II.A.5.c.(i)(A), the owner or operator must submit to the Division the following information:

II.A.8.a.(i) Quarterly or semi-annual excess emissions reports no later than the 30th day following the end of each semi-annual or quarterly period, as applicable. Excess emissions means emissions that exceed the applicable limitations contained in Section II.A.4. Excess emission reports must include the information specified in 40 CFR Part 60, Section 60.7(c) (July 1, 2018).

II.A.8.b. For affected units demonstrating compliance with Section II.A.4 using performance testing pursuant to Section II.A.5.c.(ii)(C), the owner or operator must submit to the Division the following information:

II.A.8.b.(i) Performance test reports within 60 days after completion of the performance test program. All performance test reports must determine compliance with the applicable emission limitations set by Section II.A.4.

III. Control of Emissions from Specific Major Sources of VOC and/or NOx in the 8-hour Ozone Control Area

III.A. Specific major sources of VOC and/or NOx (greater than or equal to 100 tpy) as of June 3, 2016, located in the 8-hour Ozone Control Area.

III.A.1. Stationary internal combustion engines at the following major sources must comply with applicable NOx emission limits and associated monitoring, recordkeeping, and reporting requirements in 40 CFR Part 60, Subpart IIII (July 1, 2016), 40 CFR Part 60, Subpart JJJJ (July 1, 2016), and/or 40 CFR Part 63, Subpart ZZZZ (July 1, 2016) as expeditiously as practicable, but no later than January 1, 2017:

III.A.1.a. National Reconnaissance Office (NRO) – Aerospace Data Facility (005-0028) – engines (pt 128, 139, 144).

III.A.1.b. Colorado State University (069-0011) – engines (pt 024, 035, 036, 037, 038, 040, 043, 052).

III.A.1.c. DCP Midstream, Greeley (123-0099) – engine (pt 102).

III.A.1.d. DCP Midstream, Kersey/Mewbourn (123-0090) – engine (pt 101).

III.A.1.e. DCP Midstream, Spindle (123-0015) – engines (pt 059, 075).

III.A.1.f. IBM (013-0006) – engines (pt 092, 094).

III.A.1.g. Owens-Brockway (123-4406) – engine (pt 024).

III.A.1.h. Plains End (059-0864) – engine (pt 005).

III.A.1.i. PSCo Cherokee (001-0001) – engine (pt 031).

III.A.1.j. Spindle Hill (123-5468) – engine (pt 005).

III.A.1.k. Suncor (001-0003) – engines (pt 150, 151).

III.A.1.l. Timberline Energy (123-0079) – engines (pt 010, 011).

III.A.2. Cemex Construction Materials (013-0003) must comply with applicable THC requirements and associated monitoring, recordkeeping, and reporting in 40 CFR Part 63, Subpart LLL (July 1, 2016) as expeditiously as practicable, but no later than January 1, 2017.

III.A.3. Denver Regional Landfill and Front Range Landfill (123-0079) (pt 007, 013) must comply with applicable flare requirements in 40 CFR Part 60, Subpart WWW (July 1, 2016) as expeditiously as practicable, but no later than January 1, 2017.

III.B. Specific major sources of VOC and/or NOx (greater than or equal to 50 tpy) as of January 27, 2020, located in the 8-hour Ozone Control Area.

III.B.1. Stationary internal combustion engines at the following major sources must comply with applicable NO_x emission limits and associated monitoring, recordkeeping, and reporting requirements in 40 CFR Part 60, Subpart IIII (July 1, 2016), 40 CFR Part 60, Subpart JJJJ (July 1, 2016), and/or 40 CFR Part 63, Subpart ZZZZ (January 30, 2013) as expeditiously as practicable, but no later than July 1, 2021:

III.B.1.a. University of Colorado Denver, Anschutz Medical Campus (001-0106) – engines (pts 011, 012, 013, 014, 015, 016, 017, 018, 020, 021).

III.B.1.b. Centura Health St. Anthony (059-1511) – engines (pts 002, 003).

III.B.2. Flares at the following major sources must comply with applicable flare requirements in 40 CFR Part 60, Section 60.18 (December 22, 2008) as expeditiously as practicable, but no later than July 1, 2021.

III.B.2.a. Waste Management of Colorado Denver Arapahoe Disposal Site (005-1291) (pt 003).

III.B.3. Front Range Energy (123-5097) must comply with applicable monitoring, recordkeeping, and reporting in 40 CFR Part 60, Subpart VV (July 1, 2019) as expeditiously as practicable, but no later than July 1, 2021.

IV. Control of Emissions from Breweries in the 8-hour Ozone Control Area

IV.A. Requirements for Brewing Operations

IV.A.1. Applicability

Except as provided in Section IV.A.2., the requirements of Section IV. apply to owners or operators of breweries that existed at a major source of VOC (greater than or equal to 100 tpy VOC) as of June 3, 2016, located in the 8-hour Ozone Control Area.

IV.A.2. Exemptions

The following emissions units are exempt from Sections IV.A.4. through IV.A.7. but must be maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. Owners or operators must also maintain records necessary to demonstrate that an exemption applies and make such records available to the Division upon request.

Once an emissions unit at a brewery no longer qualifies for an exemption, the owner or operator must comply with the applicable requirements of Sections IV.A.4. through IV.A.7. as expeditiously as practicable but no later than twelve (12) months after the exemption no longer applies, except as specified in Sections IV.A.2.c. and IV.A.2.d.

IV.A.2.a. An emissions unit subject to a work practice or emission control requirement in another federally enforceable section of Regulation Number 7.

IV.A.2.b. An emissions unit with total uncontrolled actual emissions less than two (2) tons per year VOC on a calendar year basis.

IV.A.2.c. Equipment or activities related to research and development. Research and development ends when the product is sold or offered for sale.

- IV.A.2.d. Newly installed, upgraded, or replaced packaging operations for a duration of six months after startup.

IV.A.3. Definitions

- IV.A.3.a. "Brewery" means a source that produces malt beverage and is comprised of emissions units related to brewhouse operations, fermentation, aging or secondary fermentation, and/or packaging operations.
- IV.A.3.b. "Packaging operation" means the canning, bottling, or filling of malt beverages into a container. Packaging operations include keg filling. Packaging operations do not include the railcar loading and unloading of beer concentrate shipped off-site for packing.
- IV.A.3.c. "Pilot brewery operation" means an operation where total packaging operations are less than 50,000 barrels per year.
- IV.A.3.d. "Process loss" means the difference between the quantity of malt beverage sent to packaging and the quantity of malt beverage packaged into a container. Process loss does not include malt beverage in filled containers if the malt beverage is processed after filling to remove or recover ethanol.

- IV.A.4. Emission limitations. By May 1, 2019, no owner or operator of a brewery may exceed an average of 6 percent process loss across all packaging operations in a calendar month and 4 percent process loss on a 12-month rolling average during packaging operations.

IV.A.5. Packaging operation work practices

- IV.A.5.a. The owner or operator must develop performance objectives and metrics for each packaging operation to reduce spillage and process loss. Process loss records must be summarized annually and compared to performance objectives established by the owner or operator. Process loss records and summaries must be made available to the Division upon request.
- IV.A.5.b. The owner or operator must develop and implement an operator training program for employees engaged in packaging operations to understand the operation of the filling lines and minimize breakdowns, spillage, and process loss. The operator training materials must be made available to the Division upon request. At a minimum, the training program must include:
 - IV.A.5.b.(i) A brewery training manager, coordinator, or equivalent;
 - IV.A.5.b.(ii) Written standard operating procedures for packaging operations;
 - IV.A.5.b.(iii) A requirement that initial training be conducted for employees performing packaging operations and more frequently for the following:
 - IV.A.5.b.(iii)(A) Employees changing packaging operation responsibilities; and

IV.A.5.b.(iii)(B) Startup of new, upgraded, or replaced packaging operations.

IV.A.5.c. The owner or operator must use and maintain packaging operation equipment to reduce container breakage and process loss. For packaging operations, except at pilot brewery operations, this includes, but is not limited to:

IV.A.5.c.(i) Using and maintaining automated filling equipment according to manufacturer recommended procedures or good engineering practices;

IV.A.5.c.(ii) Installing and operating fill level detectors to monitor the liquid fill levels in containers;

IV.A.5.c.(ii) Installing and operating crown inspectors to monitor the condition of crowns and/or caps applied to bottles, if applicable; and

IV.A.5.c.(iv) Utilizing methods to reduce container damage and spillage. This includes, but is not limited to, installing and operating container handling equipment, including smooth glide rails, lubricated conveyors, and variable speed equipment drives.

IV.A.5.d. The owner or operator of pilot brewery operations must use and maintain packaging operation equipment to reduce container breakage and process loss. This includes, but is not limited to:

IV.A.5.d.(i) Maintaining filling equipment according to manufacturer recommended procedures or good engineering practices;

IV.A.5.d.(ii) Monitoring the liquid fill levels in containers; and

IV.A.5.d.(iii) Utilizing methods to reduce container damage and spillage. This includes, but is not limited to, installing and operating container handling equipment, including smooth glide rails, lubricated conveyors, and variable speed equipment drives.

IV.A.6. Wastewater management and treatment. Owners or operators employing microbial and vegetative destruction of VOCs through the land application of wastewater must ensure that the areas where wastewater is applied are areas covered with vegetation at all times when wastewater is applied, except as required following tilling and seeding for crop rotation and field work per standard agricultural practices.

IV.A.7. Recordkeeping

The following records must be kept for a period of five (5) years and made available to the Division upon request:

IV.A.7.a. Monthly records of the percent process loss for packaging operations;

IV.A.7.b. Records necessary to demonstrate compliance with the packaging operation work practice requirements in Section IV.A.5.; and

IV.A.7.c. If applicable, pursuant to Section IV.A.6., monthly and annual records of the amount of wastewater (gallons) sent to the land application site.

V. Control of Emissions from Foam Manufacturing in the 8-hour Ozone Control Area

V.A. Requirements for Foam Product Manufacturing

V.A.1. Applicability

Except as provided in Section V.A.2., the requirements of Section V. apply to owners or operators of foam manufacturing operations that existed at a major source of VOC (greater than or equal to 50 tpy VOC) as of January 27, 2020, located in the 8-hour Ozone Control Area.

V.A.2. Exemptions

Any foam manufacturing operation that uses only non-VOC blowing agents is exempt from this Section V.A.

V.A.3. Definitions

- V.A.3.a. “Blowing agent” means any liquid, gaseous or solid substance that alone or in conjunction with other substances is capable of producing a cellular (foam) structure in a polymeric material.
- V.A.3.b. “Expandable polystyrene (EPS) beads” means polystyrene beads, particles, or granules, usually less than one-twelfth inch in diameter, that are formulated with a blowing agent (typically 3.5% to 7% of bead weight). When subjected to prescribed heating in an expansion system, the beads puff up, expanding many times their original volume into low density foam globules (called “prepuff” or “puff”) from which a variety of EPS foam products are molded.
- V.A.3.c. “Expanded polystyrene (EPS) foam” means a lightweight, foam material, made of polystyrene, from which a variety of common items are made, such as ice-chests, insulation board, protective packaging, and single-use cups.
- V.A.3.d. “Foam” means a solid material in a lightweight cellular form (having internal voids or cavities called cells that contain air or a gas) resulting from the introduction or generation of gas bubbles throughout its mass during processing.
- V.A.3.e. “Foam manufacturing operation” means any EPS production line, or portion of a production line, which processes raw EPS bead into final molded EPS product. Production line processes include, but are not limited to: pre-expansion, aging (pre-puff), and molding. The manufacturing process ends after the product exits the EPS mold. “Foam manufacturing operation” also means any production line processing methylene diphenyl diisocyanate (MDI), resins, and various hardeners and thickeners into foam products and which results in VOC emissions into the atmosphere. The manufacturing process ends after the product exits the drying tunnel.
- V.A.3.f. “Non-VOC blowing agent” means a blowing agent which does not contain VOCs.

V.A.3.g. "Polystyrene" means any grade, class, or type of thermoplastic polymer, alloy, or blend that is composed of at least 80% polymerized styrene by weight.

V.A.3.h. "Raw material" means all polystyrene, polyethylene and polypropylene, and blowing agent used in the manufacture of foam products.

V.A.4. Emission Limitations

V.A.4.a. By May 1, 2022, owners and operators of foam manufacturing operations must either

V.A.4.a.(i) Limit VOC emissions from foam manufacturing to 3.0 lbs. per 100 lbs. of total material process, averaged monthly, or

V.A.4.a.(ii) Control VOC emissions from foam manufacturing by 90%. The control device must have a control efficiency of at least 95%.

V.A.5. Work Practices

The owner or operator of any foam manufacturing operation must implement the following work practice requirements at all times to reduce VOC emissions from fugitive sources

V.A.5.a. Store raw materials in closed, leak-free, labeled containers when not in use.

V.A.5.b. Cover open containers in a manner that minimizes evaporation into the atmosphere.

V.A.6. Monitoring

V.A.6.a. The owner or operator of foam manufacturing operations must operate and maintain the control device consistent with the manufacturer's specifications.

V.A.6.b. By November 1, 2022, and every three (3) years afterward, owners or operator of foam manufacturing operations must conduct a performance test during representative operations using EPA Method 24 to determine VOC content and EPA Method 18, 25, or 25A to determine control efficiency of the emission control equipment.

V.A.7. Recordkeeping

The following records must be kept for a period of five (5) years and made available to the Division upon request

V.A.7.a. Any records necessary to demonstrate that an exemption in Section V.A.2. applies.

V.A.7.b. The amount of raw material processed on a daily basis.

V.A.7.c. The type of blowing agent used.

V.A.7.d. The amount of blowing agent used on a monthly basis.

V.A.7.e. The total monthly VOC emissions.

- V.A.7.f. For operators complying with the emission limitation in Section V.A.4.a.(i), the total monthly VOC emissions calculated on a pounds per 100 lbs. of material processed basis.
- V.A.7.g. For operators that use a control device to comply with the emission limitations in Section V.A.4.a.
- V.A.7.g.(i) A manufacturer guarantee of the control equipment's emission control efficiency to demonstrate compliance with Section V.A.4.
- V.A.7.g.(ii) The amount of supplementary natural gas combusted in the control device on a monthly basis.
- V.A.7.g.(iii) Records of performance tests conducted pursuant to Section V.A.6.
- V.A.7.h. Records of calendar year VOC emission estimates demonstrating whether the foam manufacturing operation meets or exceeds the applicability threshold in Section V.A.1.
- V.A.8. Reporting
- V.A.8.a. Performance test protocols required for performance tests under Section V.A.6.b. must be submitted to the Division for review at least thirty (30) days prior to testing and in accordance with AQCC Common Provisions Regulation Section II.C.

PART F Statements of Basis, Specific Statutory Authority and Purpose

A. December 21, 1995 (Section II.B.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act, Section 25-7-110.5, C.R.S.

Basis

Regulation Numbers 3, 7 and the Common Provisions establish lists of Negligibly Reactive Volatile Organic Compounds (NRVOCs). The revisions adopted consolidate the list of NRVOCs into the Common Provisions, assuring that the same list of NRVOCs apply to all the Colorado regulations. This provides more consistency in those chemicals regulated as VOCs.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act provides the authority for the Colorado Air Quality Control Commission to adopt and modify regulations pertaining to organic solvents and photochemical substances. Section 25-7-109(2)(f) and 25-7-109(2)(g), C.R.S., grant the Commission the authority to promulgate regulations pertaining to Organic solvents and photochemical substances. The Commission's action is taken pursuant to authority granted and procedures set forth in Sections 25-7-105, 25-7-109, and 25-7-110, C.R.S.

Purpose

These revisions to Regulations Numbers 3, 7, and the Common Provision are intended to clarify substances that are negligibly reactive VOCs, which are reflected in the EPA list of non-photochemically reactive VOCs. By consolidating the list (which consists of the EPA list of non-photochemically reactive VOCs), and adopting the EPA definition by reference, a single list of negligibly reactive VOCs will apply uniformly to all Colorado Air Quality Control Commission regulations.

This revision will also include EPA's recent addition of acetone to the negligibly reactive VOC list. The addition of acetone to the list of negligibly reactive VOC's provides additional flexibility to sources looking for an alternative to more photochemically reactive VOCs. Because the EPA has added acetone to their list of non-photochemically reactive VOCs many industries, which make and supply products to Colorado industries, are planning to substitute acetone for more reactive VOCs. This change in the content of products purchased by industry for use in Colorado would adversely affect industries in Colorado if acetone remains a regulated VOC in Colorado. By adopting acetone as a negligibly-reactive VOC, industry's will be able to take advantage of and benefit from this possible shift in product contents.

B. March 21, 1996 (Sections I.A.1. through I.A.4.; II.D.; II.E.)

The changes to Regulation Number 7 were adopted as part of the Commission's decision to redesignate the Denver metro area as an attainment and maintenance area for ozone, together with the relevant amendments to the Ambient Air Quality Standards regulation and Regulation Number 3. The Ozone Maintenance Plan, also adopted by the Commission on March 21, 1996 as part of the redesignation, based part of its demonstration of maintenance on the continued existence of rules regulating VOC emissions. Such rules include the application of the permit requirements of Regulation Number 3 to gasoline stations, and the continued application of Regulation Number 7 for the control of VOC in nonattainment areas. The VOC controls in Regulation Number 7 were adopted into the SIP in May 1995, after Denver attained the ozone standard. The maintenance demonstration was based on future inventories that assumed the continuance of existing VOC controls in the Denver Metro area.

Pursuant to Section 25-7-107(2.5), C.R.S., the Commission is required to take expeditious action to redesignate the area as an attainment area for ozone. The CAA requires the submittal of a maintenance plan demonstrating maintenance of the ozone standard for any such redesignation request. The changes to Regulation Number 7 are consistent with continued maintenance of the ozone standard and are not otherwise more stringent than the relevant federal requirements.

The purpose of the revisions to Regulation Number 7, Section I.A is to provide a de minimis source with an opportunity to obtain an exemption from the requirements of Regulation Number 7 through rule-making. This revision will be submitted to the EPA for inclusion in the State Implementation Plan (SIP). Upon inclusion of this revision in the SIP, exemptions from Regulation Number 7 adopted by the Commission shall apply for purposes of both federal and state law, pending review by the state legislature pursuant to § 25-7-133(2), C.R.S. The rule revision includes several limitations on the scope of such exemptions:

1. The aggregate of all emissions from de minimis sources may not exceed five tons of emissions per day. The purpose of this limitation is to protect the projections contained in the emissions inventory, and to prevent growth in such emissions from exceeding the National Ambient Air Quality Standard (NAAQS) for ozone.
2. An exemption may not be granted if the Division demonstrates that such exemption will cause or contribute to air pollution levels that exceed the NAAQS, even if the total aggregate emissions from such sources is less than five tons per day.

3. The Commission rule prohibits more than one rulemaking hearing per year to consider potential de minimis exemptions in the aggregate. The purpose of this provision is to prevent the granting of case-by-case exemptions, and to conserve agency resources. The granting of exemptions on a case-by-case basis would grant an unfair advantage for those sources that are able to have their case heard by the Commission before other, similarly situated sources, submit a request for a de minimis exemption. However, upon a showing of an emergency, and at the discretion of the Commission, the Commission may always grant an exemption on a case-by-case basis.
4. The Commission rule provides that the growth in emissions due to such de minimis exemptions may not exceed the growth that was included in the emissions inventory in the SIP.
5. The Commission rule requires the de minimis exemptions to be included in a permit that is subject to review and comment by the public and by EPA.

The rule revision proposed by the Regional Air Quality Council (RAQC) did not include these limitations. However, the Commission may not have used the rule as proposed by RAQC to grant unlimited exemptions from the requirements of Regulation Number 7 because such an action would undermine the regulation and the maintenance demonstration contained in the SIP. The limitations adopted by the Commission were the subject of an alternative proposal submitted by the Division. The purpose of the limit is to ensure that the de minimis exemption provision cannot be used to jeopardize attainment of the NAAQs. Such a limit is necessary in order to obtain EPA approval of this SIP revision. The alternative proposal submitted by the Division and adopted by the Commission will have no regulatory impact on any person, facility, or activity. Even without an express provision limiting the de minimis exemptions to five tons per day, the Commission generally would not have granted de minimis exemptions in excess of that amount because such emissions are not accounted for in the emissions inventory and would undermine the maintenance demonstration. Furthermore, the alternative proposed by the Division does not, by itself, create an exemption from any regulatory requirement. The alternative simply limits the scope of the exemptions that may become fully effective without a SIP revision. However, the rule does not in any way limit the Commission's authority to amend the SIP.

The emissions inventory submitted to EPA anticipated growth in emissions in both the area source and minor source categories, as well as the major source category. In order to ensure that any growth in emissions due to the granting of de minimis exemptions will not cause total emissions to exceed the growth projections for these categories, the Division will keep track of the permitted allowable emissions that may result from sources and source categories entitled to such exemptions. In addition, the growth in emissions from area, major and minor source categories will be tracked when the Division performs the periodic inventories described in the SIP for the years 1999, 2002 and 2003. Any permitted growth in emissions due to de minimis exemptions will be added to the emissions for the source categories as reflected in the most recent periodic inventory. No further de minimis exemptions will be granted if the total growth in emissions exceeds the growth projections contained in the SIP. In addition, if the total growth exceeds the growth projections contained in the SIP, one or more of the contingency measures will be implemented to offset such growth, or the SIP will be revised as necessary to ensure continued maintenance of the standard.

The purpose of the addition of Regulation Number 7, Section II.E. is to provide sources with a process to obtain approval of an alternative emission control plan, compliance method, test method, or test procedure without waiting for EPA to approve of a site-specific SIP revision. The rule provides that any such alternative must be just as effective as the relevant regulatory provision, and that such effectiveness must be demonstrated using equally effective test methods and procedures. The changes to this section delegate the authority to the Division to approve of such alternatives. Since rulemaking is not required under Section II.E., the language allowing a source to assert that the relevant regulatory provision does not represent RACT has been omitted from this section. Such a change to the substantive requirements of Regulation Number 7 would require a rule change.

The rule revision proposed by the RAQC provided that alternative emissions control plans and compliance methods must be just as effective as those contained in the rule, but did not describe the test methods to be used to demonstrate such effectiveness. The Division proposed an alternative rule requiring such effectiveness to be demonstrated using test methods and procedures that are just as effective as those set out in the rule, or that have otherwise been approved by EPA. Such criteria for test methods and procedures are necessary in order to obtain EPA approval of this SIP revision. However, even without this language in the rule the Division would have required approved test methods and procedures in order to approve of proposed alternatives. The Division's alternative proposal provides the needed certainty in the most flexible manner possible.

Furthermore, the alternative proposed by the Division does not impose any new regulatory requirement. Instead, it merely establishes criteria for allowing persons' subject to the regulation to propose, in their discretion, an alternative means of complying with the existing regulatory requirements. Therefore, the alternative proposal submitted by the Division and adopted by the Commission will have no regulatory impact on any person, facility, or activity.

The rule revisions provide that no permit may be issued based on the provisions allowing for the creation of de minimis exemptions and the approval of alternative compliance plans without first revising the SIP unless EPA first approves of such regulatory revisions as part of the State Implementation Plan. The purpose of this condition is to address the possible disapproval of these revisions by EPA. In the event these changes are not approved by EPA, the remaining regulatory provisions of Regulation Number 7 will remain in full force and effect, and therefore, the EPA may approve of the maintenance plan and the redesignation request.

The revisions to Regulation Number 7 are procedural changes that are not intended to reduce air pollution.

For clarification, the Commission adopted these regulation revisions as follows:

REGULATION REVISION	OZONE SIP AND MAINTENANCE PLAN
Section I.A.1	Exists in Appendix C of the Ozone Maintenance Plan to become a part of that document approved March 21, 1996
Sections I.A.2., 3., 4.; Section II.D., II.E.	Adopted as subsequent regulation revisions to be submitted to the Governor and EPA separately and concurrently as a revision to the Ozone SIP (and Maintenance Plan)

The specific statutory authority to promulgate the rules necessary for redesignation is set out in §§ 25-7-105(1)(a)(I) and (2); -106(1)(a); -107 (1) and (2.5); and -301. The authority to adopt such rules includes the authority to adopt exceptions to the rules, and the process for applying for any such exemptions.

C. November 21, 1996 (Section XII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act, Section 25-7-110.5, C.R.S.

Basis

Regulation Numbers 3, 7 and the Common Provisions establish lists of Negligibly Reactive Volatile Organic Compounds (NRVOCs). The revisions adopted update the list of NRVOCs so that the state list remains consistent with the federal list. Additionally, because perchloroethylene will no longer be listed as a VOC in Regulation Number 7, Section XII, Control of VOC Emissions from Dry Cleaning Facilities using Perchloroethylene as a Solvent, is being deleted.

Regulation Numbers 8 and 3 list the federal Hazardous Air Pollutants (HAPs). In the June 8, 1996 Federal Register the EPA removed Caprolactam (CAS 105-60-2) from the federal list of Hazardous Air Pollutants. The conforming changes in Regulation Number 3, Appendices B, C and D have been made to keep the list of federal HAPs in Regulation Number 3 consistent with the federal list. The list of HAPs in Regulation Number 8 has been removed and a reference to the list in Regulation Number 3 has been added.

Specific Statutory Authority

The Colorado Air Pollution Prevention and Control Act provides the authority for the Colorado Air Quality Control Commission to adopt and modify regulations pertaining to organic solvents and photochemical substances. Section 25-7-109(2)(f) and 25-7-109(2)(g), C.R.S., grant the Commission the authority to promulgate regulations pertaining to organic solvents and photochemical substances. Sections 25-7-105(1)(l)(b) and 25-7-109(2)(h) provide authority to adopt emission control regulations and emission control regulations relating to HAPs respectively. The Commission's action is taken pursuant to authority granted and procedures set forth in Sections 25-7-105, 25-7-109, and 25-7-110, C.R.S.

Purpose

These revisions to Regulation Numbers 3, 7, 8 and the Common Provisions are intended to update the state lists of NRVOCs, the Ozone SIP, and HAPs for consistency with the federal lists.

D. October 15, 1998 (Section II.F.)

The Gates Rubber Co. Site-specific Revision

The Gates Rubber Co. (Gates), by and through its attorney, submitted this Statement of Basis, Specific Statutory Authority and Purpose for amendments to Regulation Number 7, Control of Emissions of Volatile Organic Compounds.

Basis

Regulation Number 3 contains a certification and trading of emission reduction credits section (Section V), which sets forth the definitions and process for obtaining emission credits and using those credits. This section was amended to permit the use of emission reduction credits (ERC) to satisfy reasonably available control technology (RACT) requirements. The criteria for approval of ERC transactions specifies that they must involve like pollutants (for volatile organic compounds, the same degree of toxicity and photochemical reactivity), must be within the same nonattainment area, may not be used to satisfy Federal technology control requirements and may not be inconsistent with standards or regulations or to circumvent new source performance standards, best available control technology, lowest available emission rate technology controls or NESHAPs.

Regulation Number 7 sets forth CTG and RACT emission limitations, equipment requirements and work practices intended to control emission of volatile organic compounds (VOC) from new and existing stationary sources. The control measures specified in Regulation Number 7 are designed to reduce the ambient concentrations of ozone in ozone nonattainment areas and to maintain adequate air quality in other areas.

Specific Statutory Authority

The provisions of C.R.S. §§ 25-7-105 and 25-7-109 to 110 provide the specific statutory authority for the amendments to this regulation adopted by the Commission. The Commission has also adopted in compliance with C.R.S. § 24-4-103(4), this Statement of Basis, Specific Statutory Authority and Purpose.

Purpose

The purpose of this amendment to Regulation Number 7 is to establish a source specific rule for Gates to allow the use of emission reduction credits to satisfy the RACT requirements for VOC emissions pursuant to Regulation Number 7 for surface coatings operations not specifically listed in Section IX of Regulation Number 7. Regulation Number 3 provides specific authorization to use emission reduction credit transactions as an alternative compliance method to satisfy CTG and RACT requirements.

Specifically, the VOC certified emissions reduction credits to be used in this emission credit transaction in an amount up to 12 tons per year are from Coors Brewing Company pursuant to their emissions reduction credit Permit. The emission reduction credits will be used to satisfy the general requirements that all sources apply RACT. These emission reduction credits will be used by Gates so that Gates can use solvent-based surface coatings which contain VOCs periodically in lieu of the water-based coatings normally used on its 10 Cord coating line (S033, S034, and S035). These credits will allow Gates to meet RACT requirements without applying control technology to the 10 Cord line, other than the currently installed catalytic incinerator on the emissions from the drying oven from the fourth dip, which reduces those emissions by at least 90%. The relevant portion of Regulation Number 3, which applies to the Gates credit transaction is Section V.F., entitled "Criteria for Approval of all Transactions." The first requirement is that the transaction involve like pollutants. In the present case, the emission credit transaction involves the exchange of VOC pollutants. Coors credits for methanol will be exchanged for m-pyrol. Exhaust from the catalytic incinerator, which contains unconverted toluene and xylene, is routed to the curing ovens of the other zones of the 10 Cord line, including the first zone. The Division has previously found that, excluding the emissions from the non-compliant coatings addressed in this rule, the 10 Cord line has met RACT standards. The use of the non-compliant coatings adds no HAPs to the Gates emissions. Other non-criteria reportable pollutants are present at well below APEN de minimis quantities under scenario 2, which is applicable to the 10 Cord line. Regulation Number 3 further requires that toxic or VOC pollutants involve the same degree of toxicity and photochemical reactivity or else a greater reduction may be required. Since these pollutants are both toxics and VOCs (except that m-pyrol is not a toxic), both have been addressed.

All of these compounds are commonly used in the surface coating industry with appropriate safeguards during their use. With respect to toxicity of the Gates compounds, m-pyrol is not listed as a toxic compound on either the federal or state lists. Methanol, the VOC in the Coors credit, is a Bin C HAP. Because the m-pyrol in the non-compliant coatings is not a HAP, the Gates VOCs have equal or lower toxicity than those being purchased from Coors. Therefore, HAP emissions will be reduced in the airshed.

The photochemical reactivities of VOCs are important because of their impact on the ozone formation process in an airshed. The Air Pollution Control Division relied upon the work of Dr. William P.L. Carter, Professor at the University of California, whose article entitled "Development of Ozone Reactivity Scales for Volatile Organic Compounds" describes relative photochemical reactivity scales and comparisons. Dr. Carter notes that there are a number of ways to quantify VOC reactivities, but the most relevant measure of VOC effects on ozone is the actual change in ozone formation in an airshed. This results from changing the emissions of the VOC in that airshed which depends not only on how rapidly the VOC reacts and the nature of its atmospheric reaction mechanism, but also the nature of the airshed where it is emitted, including the effects of other pollutants which are present.

Dr. Carter further states that the VOC effect on ozone in the atmosphere can only be estimated using computer airshed models. The effect of changing the emissions of a given VOC on ozone formation in a particular episode will, in general, depend on the magnitude of the emissions change and on whether the VOC is being added to, subtracted from, or replacing a portion of the base case emissions.

Dr. Carter's derived relative reactivity scale includes reactive organic gases whose indices for maximum incremental reactivity (MIR) range from 0.004 to 6.5. The MIR values were updated in 1997. The VOCs and their respective MIR involved with this exchange are as follows:

Methanol	0.16
m-Pyrol	0.57

The pending emission credits of VOCs being used in the proposed emissions credit transaction are for methanol. The VOCs emitted from uncontrolled use of solvent-based coatings at Gates are from m-pyrol. Regulation Number 3 provides that if the VOCs are not of the same photochemical reactivity, a greater offset may be required. The Commission required that, based on a past ERC trade for Pioneer Metal Finishing, that methanol credits in a 1.1:1 offset ratio be exchanged for toluene and xylenes. Here, however, the Commission finds that m-pyrol and methanol have similar photochemical reactivities, so no offset will be required.

The second requirement states that the transaction must not result in an increased concentration, at the point of maximum impact of hazardous air pollutants. This provision was derived from the EPA Emissions Trading Policy Statement and referred to NESHAP requirements involved in bubble transactions. If this provision is interpreted to apply generally to a facility which is limited by an existing permit to some level of VOC emissions on a twenty-four-hour basis, any additional VOCs allowed pursuant to an emission transaction would by its application increase the concentration of VOCs at the maximum point of impact. Since it appears to have been intended to limit NESHAP offsets in bubble transactions, and no NESHAPs are applicable in the Gates transaction, and recognizing the earlier action of the Commission in approving the use of ERC transactions to satisfy CTG requirements and in approving a previous ERC transaction for Pioneer Metal Finishing, the Commission determined that this requirement should not apply to this transaction.

The next requirement states that no transaction may be approved which is inconsistent with any standard established by the Federal Act, the state Air Quality Control Act or the regulations promulgated under either, or to circumvent NSPS requirements or BACT or LAER, although the Commission may approve a transaction using a certified emission reduction credit in lieu of a specified CTG method or RACT. The emissions involved in this transaction at Gates are not subject to NSPS, BACT, or LAER. Regulation Number 7 applies only RACT to the Gates operations involved. Regulation Number 3 clearly permits the use of emission reduction credits to satisfy RACT.

The emission must involve sources which are located within the same nonattainment area. In the present case, both Gates, whose operations are located at 900 S. Broadway, Denver, Colorado, who is proposing to use the credits, and the source of the credits, Verticel, whose operations were located at 4607 South Windermere Street, Englewood, Colorado, are located in the Denver nonattainment area, less than five miles apart.

The next requirement prohibits the use of emission reduction credits to meet applicable technology-based requirements for new sources, such as NSPS, BACT, or LAER. As stated, the Gates operations involved in this transaction are not subject to NSPS, BACT, or LAER or any other technology-based requirement except for RACT requirements for which an ERC transaction may be used to satisfy such requirements.

The next requirement states that VOC trades will be considered equal in ambient effect where the trade is a pound for pound trade in the same control strategy demonstration area. It appears that this requirement, which was taken from the EPA Emissions Trading Policy Statement, made the assumption that the "pound for pound" trend would have an equal impact on the ambient environment, with respect to ozone. Since there was no independent photochemical reactivity equivalency requirement in the 1986 Policy Statement, this requirement appears to be redundant with the requirement for insuring the same degree of photochemical reactivity among traded pollutants.

For VOC trades involving surface coating, the requirements state that emissions must be calculated on a solids-applied basis and must specify the maximum time period over which the emissions may be averaged, not to exceed 24 hours. The proposed emissions credit transaction is based on a 24-hour period. With respect to the solids-applied basis calculation, this transaction will be calculated on the basis of the pounds of VOCs from uncontrolled solvent-based coatings.

The emissions credit transaction will require a SIP revision. The source specific rule for Gates will be forwarded to EPA for approval. The state emissions permit for Gates pursuant to the emissions credit transaction will be state effective (but not federally effective) until the SIP revision is approved by EPA.

Gates proposed the following VOC emissions limitation in its state permit taking into consideration the pounds per year VOC emissions allowed by this emissions credit transaction:

1. A daily maximum limitation of 400 lbs. of VOC emissions from uncontrolled solvent-based surface coatings, calculated on a monthly basis for compliance purposes. Calculations will be performed by the 30th of the following month.
2. An annual limitation of no more than 24,000 lbs. (12 tons) of VOC emissions from uncontrolled solvent-based surface coatings.

Gates proposes to calculate the annual total VOC limitation on a rolling 12-month basis. Gates further proposes to keep monthly totals of non-compliant surface coatings used and to calculate daily usage based on monthly usage divided by the number of days' non-compliant surface coatings were used. Records of usages and calculations will be kept and produced at the Division's request.

This source-specific rule has a negligible or no effect upon the other provisions of the ozone SIP.

It is contemplated that a State construction permit will be issued to Gates upon final approval by the Commission. Should the approval come after the issuance of Gates' Title V operating permit, the terms of the construction permit will be added to the operating permit.

E. January 11, 2001 (Sections III.C., IX.L.2.c.(1), and X.D.2. through XI.A.3.)

Readoption of Changes to Regulation Number 7 that were not printed in the regulation or the Colorado Code of Regulations.

Background

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Administrative Procedures Act, C.R.S. (1988), Sections 24-4-103(4) and (12.5) for adopted or modified regulations.

Basis

During a review of the version of Regulation Number 7 adopted by the Air Quality Control Commission and the version of Regulation Number 7 published in the Colorado Code of Regulations, several significant discrepancies have been identified. This rule making will clarify the Commission's intent to adopt the following revisions to Regulation Number 7:

1. Section III.C regarding General Requirements for Storage of Volatile Organic Compounds omits the following revision:

"Beer production and associated beer container storage and transfer operations involving volatile organic compounds with a true vapor pressure of less than 1.5 PSIA at actual conditions are exempt from the provisions of Section III.B."
2. Section IX.L.2.c.(i) contains discrepancies in reference to the permit number of Coors Brewing Company Emissions Reduction Credit Permit issued on July 25, 1994.
3. Section X.D.2. through Section XI.A.3. was omitted from the CCR as published in the current version of Regulation Number 7.

Authority

Sections 25-7-109, C.R.S. (1997) authorize the Commission to adopt emission control regulations.

Purpose

Re-adoption of the proposed rule will eliminate the discrepancies between the Commission's adopted provisions within Regulation Number 7 and those contained within the Colorado Code of Regulations. Adoption of the amendments will benefit the regulated community by providing sources with consistent information.

F. November 20, 2003 (Sections I.A.2. through I.A.4., II.D. and II.E.)

The Commission repealed the provisions establishing a procedure for granting exemptions for de minimis sources, and the procedure for approving alternative compliance plans without source-specific SIP revisions. The Commission had adopted the repealed provisions in March 1996, but had delayed the effective date pending EPA approval through the SIP revision process. Earlier this year, EPA informed the Commission of its intent to disapprove the provisions unless they were withdrawn. Thus, the provisions that are the subject of this rulemaking action never took effect. The Commission hereby repeals such provisions in order to avoid disapproval of the earlier SIP submittal, and to remove extraneous provisions from Regulation Number 7. Such repeal is required in order to comply with federal requirements, and is not otherwise more stringent than the requirements of the federal act.

Sections 25-7-105(1)(a)(I) and 25-7-301 authorize the Commission to adopt and revise a comprehensive SIP, and to regulate emissions from stationary sources, as necessary to maintain the national ambient air quality standard for ozone in accordance with the federal act.

G. (March 2004, Sections I.A, I.B., XII., and XVI.

The March 2004 revisions were adopted in conjunction with the Early Action Compact Ozone Action Plan, which is a SIP revision for attainment of the 8-hour ozone standard by December 31, 2007. The Commission adopted four new control measures in Regulation Number 7 to reduce emissions of volatile organic compounds (VOC). The control measures require the installation of air pollution control technology to control: (1) VOC emissions from condensate operation at oil and gas (E&P) facilities; (2) emissions from stationary and portable reciprocating internal combustion engines; (3) certain VOC emissions from gas-processing plants; and, (4) emissions from dehydrators at oil and gas operations.

The new requirements in Sections XII., and XVI. apply to a larger geographic area than the pre-existing requirements of Regulation Number 7, as set out in Section I.A. of the rule. The reference to the "Denver Metro Attainment Maintenance Area", which is not a defined term, in Section I.A was changed to refer to the "Denver 1-hour ozone attainment/maintenance area", which is defined in the Ambient Air Quality Standards Rule. Similarly, the reference to the "Denver Metropolitan Nonattainment Area Ozone Maintenance State Implementation Plan" was changed to the "Ozone Redesignation Request and Maintenance Plan for the Denver Metropolitan Area," which is the correct name of the document submitted to EPA in May 2001.

Regarding VOC emissions from condensate operations, the Commission has determined that an overall reduction of 47.5% VOCs is required of each E&P operation so as to meet the requirements of the SIP. Further the Commission decided not to take a unit-by-unit approach, but rather, the amendments take a more flexible approach to regulating such emissions by requiring sources that have filed, or were required to file, APENs to choose emission controls and locations for applying those controls. This approach also minimizes the risk that sources may reconfigure tanks to avoid implementing the regulation.

Section XII.A.6. provides an exemption for owners and operators with less than 30 tpy of flash emissions subject to APEN reporting requirements. Regulation Number 7 previously included more general exemptions for emissions from condensate operations, but such pre-existing exemptions should have been repealed as part of this revision to Regulation Number 7. To the extent any pre-existing exemption for condensate operations remains, such pre-existing exemption shall not be construed to supersede the requirements of Section XII.

The rule also requires annual reports describing how E&P sources will achieve the requisite emission reductions. Such reports are necessary so that the Division can determine whether or not the emission reductions are being achieved.

Section XII.B. of Regulation Number 7 is required to ensure that existing and new natural gas processing plants employ air pollution control technology to control emissions from leaking equipment, and atmospheric condensate storage tanks (and tank batteries). The Commission is specifically requiring a leak detection and repair (LDAR) program for all gas plants, according to the provisions of 40 CFR Part 60, Subpart KKK, regardless of the date of construction of the affected facility. This is necessary to ensure these large facilities are well controlled and VOC emissions minimized.

Section XII. C. pertains to control of VOC emissions from natural gas dehydration operations. The Commission determined that, in order to meet the requirements of the SIP, emissions must be reduced from all dehydration operations located in the 8-hour Ozone Control Area if such operations produce emissions above the minimum threshold specified in the rule. Further the Commission decided that flexibility should be allowed in how emissions are reduced, so several options are listed from which a source owner or operator may choose. If other equally effective measures or control devices are available, the Division may, on a case-by-case basis, approve the use of such alternatives.

Similarly, Section XVI. establishes controls for reciprocating internal combustion engines. Both "lean" and "rich" burn engines are addressed and though the Commission has specified the default control technology to be applied to each engine type, the Division is allowed to approve alternative technology if a demonstration can be made that the alternative is at least as effective as the listed device in reducing VOC emissions. Parties to the rulemaking hearing provided evidence that suitable, cost-effective control equipment may not be available for some existing engines. The rule adopted by the Commission includes an exemption for lean burn engines if the owner demonstrates that such emissions controls would cost \$5,000 or more per ton of VOC removed. In calculating such costs, the Division shall use an appropriate amortization period and current discount rate. The Commission directs the Division to further investigate the question of whether controls are available and suitable for lean burn engines, and to recommend any revisions necessary for the regulation applicable to such engines. New engines locating in the control area must comply with the requirements effective June 1, 2004, but existing engines have until May 1, 2005 to come into compliance. Since the rule provides an exemption for existing engines that cannot be controlled for less than \$5,000 per ton, the rule must make the distinction between new and existing engines so that engines will not be moved into the area during prior to May 2005 and subsequently apply for such an exemption.

The Commission recognizes that, at this point in time, the controls required by the rule amendments constitute Reasonably Available Control Technology (RACT), at a minimum, and in some cases, the controls mandated by this regulation may, in fact, constitute Best Available Control Technology (BACT). This means that this regulation shall not be used: (a) to preclude a source from asserting that one of the controls mandated herein constitutes BACT or Lowest Achievable Emissions Rate (LAER) for a new source or major modification, (b) require the Division or Commission to mandate different control technologies as BACT, or (c) preclude the Division or Commission from requiring additional or more stringent air pollution control technologies as necessary or appropriate to comply with applicable BACT or LAER requirements for new sources and major modifications.

By its terms, the New Source Performance Standard (NSPS) applicable to leaking equipment at onshore natural gas processing plants (40 CFR Part 60, Subpart KKK) applies to "affected facilities" and "process units" at such facilities as those terms are defined in the standard. In general, plants that were constructed prior to January 20, 1984 are exempt from the standard, unless subsequently modified or reconstructed, or newly constructed after that date. Since process units at a single gas plant can be distinct, certain gas plants may contain equipment that is not presently subject to the NSPS because of its date of construction. The control requirement in Section XII.B. would extend leak detection and repair program requirements to such equipment.

The statutory authority for the revisions to regulation Number 7 is set out in Sections 25-7-105(1)(a) and (1)(b); 25-7-106(1)(c), (5) and (6); and 25-7-109(1)(a) and (2), C.R.S.

The March 2004 revisions to Regulation Number 7 are based on reasonably available, validated, reviewed, and sound scientific methodologies. All validated, reviewed and sound scientific methodologies and information made available by interested parties has been considered. Evidence in the record supports the finding that the rule shall result in a demonstrable reduction in air pollution. The Commission chose the most cost-effective mix of control strategies available to comply with the 8-hour ozone NAAQS. Where possible, the regulations provide the regulated community with flexibility to achieve the necessary reductions. The Commission chose the regulatory alternative that will maximize the air quality benefits in the most cost-effective manner.

H. (December 2004, SECTIONS I.A., II.A., XII. and XVI.)

The December 2004 revisions were adopted to respond to U.S. EPA comments on the Ozone Action Plan the Commission adopted in March 2004. EPA required the rule revision in order to make the control measures incorporated into the State Implementation Plan practically enforceable as required by the federal Clean Air Act. The Federal Act requires all of the regulatory provisions adopted in this rulemaking action, and none of the provisions are more stringent than the requirements of the federal act.

The revised rule includes a process for obtaining emission reduction credit for pollution prevention measures. In order to qualify for an emission reduction credit, a pollution prevention measures must, among other things, be included in a permit even if it does not involve the construction of an air pollution source and would not otherwise trigger a requirement for a permit. The revisions to the regulation do not, however, create a requirement for sources to obtain a permit for pollution prevention measures for which the source will not take emissions reduction credit.

The Commission has the statutory authority to adopt the revisions pursuant to Sections 25-7-105(1)(a) and (1)(b); 25-7-106(1)(c), (5) and (6); and 25-7-109(1)(a) and (2), C.R.S.

The control measures necessary to achieve the 8-hour ozone standard were adopted in March 2004. The December 2004 rule changes do not impose new emission control requirements or emission reduction requirements on industry. Instead, the December 2004 rule revisions are intended to make the previously adopted requirements more enforceable, and to make sure that the requisite emission reductions occur during the ozone season when they are needed. Thus, the December 2004 are administrative in nature in that they are intended to assist with the administration and enforcement of the previously adopted controls. The Commission recognizes that the December 2004 rule amendments impose additional recordkeeping and reporting requirements, and therefore costs, on the regulated community. The changes, however, are not intended to achieve further reduction in emissions of volatile organic compounds beyond the reduction requirements adopted in March 2004. They are instead intended to make the March 2004 revisions fully enforceable and acceptable to EPA. Since the December 2004 rule changes are administrative in nature, the requirements of Section 25-7-110.8 C.R.S. do not apply.

I. December 17, 2006 (Section XII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), C.R.S. for new and revised regulations.

Basis

Regulation Number 7, Section XII imposes emission control requirements on oil and gas condensate tanks located in Adams, Arapahoe, Boulder, Douglas and Jefferson Counties, the Cities and Counties of Broomfield and Denver and parts of Larimer and Weld Counties ("8-Hour Ozone Control Area"). The condensate tank requirements, along with other requirements applicable to oil and gas operations and natural gas fired reciprocating internal combustion engines, were initially promulgated in March 2004, and later revised in December 2004, in connection with an Early Action Compact Ozone Action Plan ("EAC") entered into between the State of Colorado and the United States Environmental Protection Agency. The purpose of the EAC is to prevent exceedances of the 8-Hour Ozone Standard and avoid a nonattainment designation for the area. Pursuant to the EAC, Colorado committed to limiting Volatile Organic Compound ("VOC") emissions from condensate tanks located in the 8-Hour Ozone Control Area to 91.3 tons per day ("TPD") as of May 1, 2007 and 100.9 TPD as of May 1, 2012. Because of unanticipated growth of condensate tank emissions since 2004, the control requirements for condensate tanks adopted during the 2004 rulemaking are insufficient to meet these daily emission numbers. The current revisions require a greater level of control of condensate tank emissions in the 8-Hour Ozone Control Area in order to meet the commitments set forth in the EAC and to prevent future exceedances of the 8-Hour Ozone Standard.

These revisions are based on reasonably available, validated, reviewed and sound scientific methodologies. All validated, reviewed and sound scientific methodologies made available by interested parties have been considered. Evidence in the record supports the finding that the rule shall result in a demonstrable reduction in air pollution, and will reduce the risk to human health or the environment or otherwise provide benefits justifying the costs. Among the options considered, the regulatory option chosen will maximize the air quality benefits in the most cost-effective manner.

Specific Statutory Authority

The specific statutory authority for these revisions is set forth in Section, 25-7-105(1)(a), C.R.S., which gives the Air Quality Control Commission authority to promulgate rules and regulations necessary for the proper implementation of a comprehensive state implementation plan that will assure attainment of national ambient air quality standards. Additional authority for these revisions is set forth in Sections, 25-7-106 and 25-7-109, which allow the Commission to promulgate emission control regulations and recordkeeping requirements applicable to air pollution sources. Specifically, Section 25-7-106(1)(c) authorizes the Commission to adopt emission control regulations that are applicable to specified areas within the state. Section 25-7-109(1)(a) authorizes the Commission to adopt emission control regulations. Section 25-7-109(3)(b) authorizes the Commission to adopt emission control regulations for the storage and transfer of petroleum products and any other volatile organic compounds.

Purpose

The Revisions to Section XII. were adopted in order to meet the commitments with respect to condensate tank emissions set forth in the Early Action Compact Ozone Action Plan entered into between the State of Colorado and U.S. EPA, prevent exceedances of the 8-Hour Ozone Standard, and simplify recordkeeping and reporting requirements. To accomplish these goals, the revised regulation raises the system-wide control requirements for the ozone season from the current 47.5% to 75% commencing in 2007 and 78% in 2012. While the rule establishes a higher percentage reduction in 2012 the Commission recognizes that given the uncertainty of emissions growth over the next 6 years, this reduction requirement may be too high and may need to be revisited as the 2012 deadline approaches. For the non-ozone season the required reduction has been raised from 38% to 60% commencing October 2007, and 70% commencing January 1, 2008. Determination of compliance during the ozone season under the revisions will be on a weekly basis instead of a daily basis, in recognition of the fact that condensate production is not typically measured on a daily basis. Under the previous version of the Rule, production could be tracked on something greater than a daily basis and the total divided by the number of days to obtain a daily number. As such, the prior rule did not truly give a daily average and thus the move to a weekly average is of little substance. Apart from this change, calculation of emissions for compliance purposes will remain the same as under the previous version of the rule.

In addition to raising the system-wide reduction requirements, the current rule adds significant new monitoring, record-keeping and reporting requirements, and a "backstop" threshold requirement to have emission controls on all condensate storage tanks with uncontrolled actual emissions of 20 tpy or more of VOC flash emission, as a state-only requirement within the EAC area pursuant to Section XVII.C.1. of Regulation Number 7. Owners and operators will continue to keep a spreadsheet that tracks emission reductions and submit an Annual Report as required under the previous version of the rule. Owners and operators are now also required to submit a semi-annual report on November 30 of each year detailing their emissions during the preceding ozone season. Additional record keeping has been added so as to require that a weekly checklist be maintained detailing inspections of control devices. This checklist will assist operators in the inspection and maintenance practice and provide a record that proper inspections have been done. If the inspections show a problem with the control device, the owner or operator will be required to notify the Division of problems on a monthly basis. This requirement will allow the Division to track problems on a timelier basis and ensure compliance with the rule. Finally, a provision has been added to require owners or operators to submit a list of all their controlled tanks on April 30 of each year and notify the Division monthly during ozone season if the control status of any tank changes.

J. December 17, 2006 (Sections I.A.1.b. and XVII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), C.R.S. for new and revised regulations.

Basis

The Air Quality Control Commission has adopted these state-only provisions as a means of reducing air emissions from oil and gas operations throughout Colorado. Due to the large growth in oil and gas production in a number of regions of the state emissions from oil and gas operations have rapidly increased over the past few years and are expected to increase further in the foreseeable future. These revisions are a proactive measure designed to eliminate air emissions that could threaten attainment of ambient air quality standards and adversely affect visibility in Class I Areas. These revisions are based on reasonably available, validated, reviewed and sound scientific methodologies. All validated, reviewed and sound scientific methodologies made available by interested parties have been considered. Evidence in the record supports the finding that the rule shall result in a demonstrable reduction in air pollution, and will reduce the risk to human health or the environment or otherwise provide benefits justifying the costs. Among the options considered, the regulatory option chosen will maximize the air quality benefits in the most cost-effective manner.

Specific Statutory Authority

The specific statutory authority for these revisions is set forth in Sections 25-7-106 and 25-7-109 of the Colorado Air Pollution Prevention and Control Act ("Act"), which allow the Commission to promulgate emission control regulations and recordkeeping requirements applicable to air pollution sources. Additional authority is set forth in Section 25-7-105.1, which allows the Commission to adopt state-only standards. Specifically, Section 25-7-106(1)(c) authorizes the Commission to adopt emission control regulations that are applicable to the entire state. Section 25-7-109(1)(a) authorizes the Commission to adopt emission control regulations. Section 25-7-109(3)(b) authorizes the Commission to adopt emission control regulations for the storage and transfer of petroleum products and any other volatile organic compounds.

Purpose

The Revisions to Section XVII. were adopted in order to reduce air emissions from oil and gas operations and natural gas fired reciprocating internal combustion engines in Colorado. These revisions constitute a forward-looking approach to deal with a rapidly growing source of air emissions, and are designed to reduce the possibility of future problems with respect to the attainment of National Ambient Air Quality Standards and state and federal Class I Area visibility goals. Since the requirements are not mandated under federal law and are not currently necessary to meet National Ambient Air Quality Standards they are being adopted as a state-only requirement in accordance with the Act and as provided for under the Federal Clean Air Act.

These revisions establish emission control requirements for condensate storage tanks, glycol dehydrators and natural gas fired reciprocating internal combustion engines in Colorado. These provisions require that condensate tank and dehydrator controls meet a 95% percent control efficiency. As in the EAC Area, this requirement does not contemplate stack testing in order to verify the control efficiency. The insertion of the word average allows operators some downtime without a violation occurring so long as the downtime does not result in an average control efficiency of less than 95% considering the actual engineered control efficiency. For the purposes of XVII.C.4.b. observed operation of flare auto-igniters can include telemetric monitoring systems, physical on-site function tests or auditory confirmation of the auto-igniter function.

The requirements applicable to glycol dehydrators mirror the requirements applicable in the 8-Hour Ozone Control Area set forth in Section XII, and should be interpreted consistently with those provisions notwithstanding the addition of clarifying language. For example, language has been added clarifying that grouping of dehydrators is limited to dehydrators at a single site. Similarly, the word “production” has been added to the definition of condensate tank to clarify that the requirements, as within the EAC, do not apply to produced water tanks.

Determination of whether a condensate tank’s emissions are at or above the threshold is based on the emissions from the tank during the preceding twelve-month period. If a tank has been in service for less than twelve months, applicability shall be based on uncontrolled actual emissions over the service period of the tank multiplied out to twelve months. Accordingly, if a tank has been in service for three months, applicability of the control requirements will be based on the uncontrolled actual emissions from the tank for those three months multiplied by four. If emissions from a controlled tank decrease, operators may remove the controls when emissions from the previous twelve-month period falls below the applicable threshold. Operators will remain responsible, however, for controlling a tank if a subsequent emission increase results in emissions being over the applicable threshold during the preceding twelve months. For tanks serving newly drilled, recompleated or restimulated wells (including refrac’d wells) the owner or operator will have 90 days to determine anticipated production and, if necessary install a control device. In determining anticipated production, the owner or operator may use an appropriate decline factor to determine expected emissions over the first 12 months after the new drilling, recompletion or re-stimulation. If the owner or operator determines that emissions will be below the 20 tpy threshold following the new drilling, recompletion or restimulation, the owner or operator shall notify the Division of this determination.

Certain differences with the requirements applicable to the 8-Hour Ozone Control Area have been included in order to provide greater flexibility to operators in other areas of the state and in light of the fact that the regulation represents a proactive attempt to avoid future impacts from oil and gas emissions. Specifically, the standards for obtaining approval of an alternative pollution control device have been relaxed to promote innovative control strategies. Additionally, a provision has been added to allow an extension of the control requirement deadlines at the Division’s discretion for good cause shown. This provision allows the Division to extend a deadline where shortages of control equipment, and crews may prevent an operator from meeting the deadlines, particularly in areas where access is limited by the weather or other issues. With respect to Section VII.B.1.c. of the General Provisions, the Commission has determined that as a general rule during normal operations no emissions should be visible from the air pollution control equipment.

Normal operations include reasonably foreseeable fluctuations in emissions from the condensate tank, including the fluctuations that occur during a separator dump. However, a transient (lasting less than 10 seconds) “puff” of smoke when the main burner ignites or shuts down would not be considered a violation of the “no visible emission” standard. Finally, a provision has been included that exempts units’ subject to the rule if such units are also subject to a control standard under the MACT, BACT or NSPS Programs. This exception is of most importance for new and newly relocated engines that may become subject to a currently pending NSPS Standard under Subpart JJJJ.

The engine provisions only apply to engines that are constructed or relocated into Colorado after the applicability date and do not impose requirements on units that are currently located in the state.

The Commission recognizes that the adopted emission control requirements represent a first step in addressing rapidly growing emissions from oil and gas operations throughout the state. Accordingly, the Commission directs the Division to provide an annual update on emission growth trends, environmental impacts, modeling and monitoring efforts, the adequacy of emission controls to protect the NAAQS and the health impacts of emissions from the oil and gas sector.

K. December 12, 2008 (Title, Sections I., II., VI. – XIII., XVII., XVIII., and Appendices A-F)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), C.R.S. for new and revised regulations.

Basis

The Air Quality Control Commission has adopted revisions throughout Regulation Number 7 to address ozone formation in the 8-Hour Ozone Nonattainment Area (NAA), including the 9-county Denver Metropolitan Area and North Front Range (DMA/NFR) NAA. Specifically, the Commission has adopted revisions to reduce an ozone precursor, volatile organic compound (VOC) emissions, and thus reduce ozone formation. These revisions are necessary to ensure attainment with the current 8-Hour Ozone National Ambient Air Quality Standard (NAAQS) set at 0.08 parts per million (ppm), and to achieve additional ozone reductions in light of both the new ozone NAAQS set at 0.075 ppm and the Governor's July 27, 2007 directive to proactively and pragmatically reduce ozone levels.

As of November 20, 2007, the EPA's deferral of a nonattainment designation for the area in question expired, signifying that the area is now considered nonattainment, or in violation of the 1997 8-hour Ozone NAAQS of 0.08 ppm for ground level ozone. The DMA/NFR includes all of Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, and Jefferson Counties as well as portions of Larimer and Weld Counties. This area is now known as the DMA/NFR NAA.

Pursuant to the Federal Clean Air Act, Colorado must prepare and submit a revision to the State Implementation Plan (SIP) to the EPA no later than June 30, 2009 that demonstrates attainment of the 8-Hour Ozone NAAQS no later than 2010. The Commission has adopted an Attainment Plan that satisfies this requirement. The Attainment Plan demonstrates attainment with no additional control measures.

Photochemical grid dispersion modeling indicates that without further emission controls, Colorado will attain the 8-hour standard by 2010. The dispersion modeling reflects that Colorado would attain the standard by a narrow margin. Photochemical dispersion modeling analysis is the primary tool used to assess present and future air quality trends, and is required for EPA to approve the state attainment demonstration in the SIP.

In addition, pursuant to EPA guidance, if modeling results indicate that the highest ozone levels will fall between 0.082 and 0.087 ppm, Colorado must conduct a "weight of evidence" analysis and other supplemental analyses in order to corroborate the modeling results. Colorado's model results are within this range, and thus the state has conducted this analysis. The analysis supports the conclusion that Colorado will attain the standard by 2010.

The Commission is also adopting State-only revisions to Regulation Number 7 to further address ozone formation in the DMA/NFR NAA. Specifically, the Commission has adopted revisions to reduce an ozone precursor, volatile organic compound (VOC) emissions, and thus reduce ozone formation. These revisions help Colorado make progress toward eventual compliance with the new ozone NAAQS set at 0.075 ppm as well as the Governor's directive to proactively and pragmatically reduce ozone levels.

Statutory Authority

The statutory authority for these revisions is set forth in the Colorado Air Pollution Prevention and Control Act ("Act"), C.R.S. § 25-7-101, et seq., specifically, C.R.S. §25-7-105(12) (authorizing rules necessary to implement the provisions of the emission notice and construction permit programs and the minimum elements of the operating permit program), 109(1)(a), (2) and (3) (authorizing rules requiring effective practical air pollution controls for significant sources and categories of sources, including rules pertaining to nitrogen oxides and hydrocarbons, photochemical substances, as well as rules pertaining to the storage and transfer of petroleum products and any other VOCs), and § 25-7-301 (authorizing the development of a program for the attainment and maintenance of the NAAQS).

Purpose

These revisions to Regulation Number 7 are part of an overall ozone reduction strategy. The Commission intends that this overall ozone reduction strategy accomplishes six objectives: A) reduce VOC and nitrogen oxides' (NOx) emissions from oil and gas operations in the Ozone NAA and across the state, B) revise the control requirements for condensate tanks by a refined system-wide control strategy in the Ozone NAA, C) expand VOC RACT requirements for listed source categories for 100 tpy sources such that all Ozone NAAs are subject to Regulation Number 7's RACT requirements, D) clarify how the RACT requirements in Regulation Numbers 3 and 7 interact in the Ozone NAA, E) improve the Division's inventory of condensate emissions and other relevant sources in the NAA; and F) make typographical, grammatical and formatting changes for greater clarity and readability.

In support of objectives A-D and F, the Commission adopts these revisions to Regulation Number 7 to revise condensate tank regulations, set pneumatic controller regulations, expand RACT applicability and make associated corrections (Regulation Number 7, Sections I., II., VI. – XIII., XVII., XVIII., and Appendices A-F).

In the course of this proceeding, the Division and certain parties supported a compromise proposal regarding the control of condensate tanks. The Commission finds this proposal to be appropriate with certain changes noted herein. The Commission is requiring an increase from 75% to 81% control on a system-wide basis in 2009; to 85% control on a system-wide basis in 2010; and to 90% control on a system-wide basis in 2011 in the 8-Hour Ozone NAA. The Commission is adopting new VOC controls for pneumatic controllers in the 8-Hour Ozone NAA in Regulation Number 7, Section XVIII.

These system-wide control percentages achieve significant ozone precursor reductions in 2009, 2010 and 2011, with emphasis on significant VOC emissions reductions in 2010, during the monitoring period for the attainment demonstration. These revisions will help to ensure that the non-attainment area realizes the necessary reductions during the 2010 attainment year. Further, these revisions are an important step in putting the State on a path towards attaining the 2008 8-Hour ozone standard. A number of parties including the Regional Air Quality Council and the North Front Range Metropolitan Planning Organization supported this proposal to secure VOC reductions from this source at these levels and according to this schedule. The system-wide approach has been approved by the Commission in the past, as well as by EPA in revisions to the State Implementation Plan. The Commission decided to defer decision making on the implementation of a 95% system-wide level of control, given concerns regarding the notable incremental cost associated with control to the equivalent of 2 tpy tanks as well as concerns regarding the flexibility intended to be afforded by a system-wide approach. Tank operators also expressed concern about the loss of incentive to over-control their systems to meet the standard, and the difficulty for small operators to control at the 95% system-wide level at this time.

The proposed control percentages continue to afford flexibility in operations to condensate tank operators, while ensuring attainment of the standard by 2010. Therefore, the Commission is deferring further control for future modeling, air quality analysis, and/or administrative review, whether to control this source in the future at the 95% system-wide control level or through some other approach for purposes of the 2008 8-Hour standard.

The provisions of the compromise proposal, including the commensurate emissions reductions, support the State Implementation Plan's ability to assure attainment and maintenance of the 1997 8-Hour Ozone NAAQS. Inclusion of these provisions enhances the Weight of Evidence demonstration supporting attainment by 2010 pursuant to this State Implementation Plan. The Commission recognizes parties subject to the compromise Regulation Number 7 provisions for condensate tank system-wide emissions reductions concur that these provisions are appropriate for inclusion in the State Implementation Plan.

Further the Commission intends to expand the applicability of RACT requirements to existing, new and modified sources in Ozone NAAs outside of the historic one-hour Ozone NAA or attainment/maintenance area (Regulation Number 7, Sections I and II). The Commission further intends to clarify how the control technology requirements of Regulation Number 7 interact with Regulation 3, Part B, Section II.D.2.

Finally, the Commission intends to make grammatical, typographical, formatting revisions, and other editing revisions throughout Regulation Number 7.

Condensate Tank Emissions Control

Condensate storage tank control requirements in Regulation Number 7, Section XII. are revised by reorganizing the rule, adding/revising definitions, adding monitoring requirements, revising recordkeeping and reporting requirements, and setting additional control requirements for tanks. The current requirements are reorganized by specifying applicability, definitions, general provisions, emissions controls, monitoring, and recordkeeping and reporting sections. The terms new, existing, modified/modification, auto-igniter, and surveillance system were defined.

Tanks serving newly drilled, recompleted or stimulated wells are required to employ air pollution control equipment during the first 90 days of production. After the first 90 calendar days, the control device may be removed. This requirement is designed to address the fact that production, and thus emissions, is at their greatest during the period immediately after drilling, recompletion or stimulation, and the fact that the actual production/emission level is not known prior to drilling, recompletion or stimulation. By requiring controls on all tanks serving newly drilled, recompleted or stimulated wells, the proposed rule significantly reduces emissions during the initial period, while allowing owners and operators to remove control devices afterward, as part of the overall system-wide control regime. All tanks over 2 tpy must participate in the overall system-wide program. Furthermore, since Regulation Number 7's system-wide program is essentially RACT for condensate tanks in the NAA, new and modified 2 tpy or greater condensate tanks (affected by Regulation Number 3 RACT) may also move their control devices after the first 90 days when participating in the overall system-wide control regime, as long as the overall system-wide requirements are being met. Such flexibility is provided as to avoid two regulatory programs: one for tanks that might never be allowed to move their control devices under Regulation Number 3 RACT and one for tanks that would be allowed the flexibility under a system-wide program. Finally, it is the intent of this rule that sources may use their 2 tpy or greater "modified" tanks emissions (i.e., during those tanks' first 90 days of production) in the source's overall system wide calculation. After 90 days, sources must include – whether controlled or otherwise - the 2 tpy or greater "modified" tanks in the overall system-wide calculation. In the case of modified tanks that fall below 2 tpy, it is not the intent of the commission for sources to include these less than 2 tpy tanks in any system-wide calculation. However, sources may use the less than 2 tpy controlled tanks, if necessary to demonstrate system-wide compliance.

The Commission is requiring the installation and operation of auto-igniters for each combustion device. In many cases, condensate tanks are remotely located and unmanned. Auto-igniters will provide greater assurance that the control devices are functioning, under these circumstances. Auto-igniters may be relied on to identify when the pilot is not lit and attempt to relight it, and ensure control operation. The Commission is also requiring surveillance on batteries with uncontrolled emissions greater than 100 tpy. Operators must use surveillance to document the duration of time when the pilot is not lit, and to discover if repairs are necessary to ensure proper control operation. The Commission is targeting this size of battery in order to strike a balance between the need to more carefully monitor performance among the largest batteries, the cost associated with surveillance and the division's capacity to manage the information. The Commission acknowledges that three well operators, Encana, Anadarko and Noble Energy, have agreed to participate with the Division in a pilot program regarding the implementation of electronic surveillance systems.

With regard to recordkeeping and reporting requirements, operators will still record estimated emissions each week (as part of the current Regulation Number 7 requirements) and will report this information to the Division semi-annually. In addition, the Division has revised these requirements so that sources now must keep monthly records throughout the year and provide any of those records within 5 business days of a division request. Further, operators may only use a Division-approved spreadsheet to submit emissions records. Further, a responsible official must now certify the accuracy of the data in the semi-annual reports. This level of recordkeeping and reporting will allow the Division greater capacity to verify compliance and additional availability to work with sources (especially smaller operators). The Commission intends that record-keeping and reporting requirements for surveillance apply only to tanks with uncontrolled emissions greater than 100 tpy.

Controls on 2 Tons Per Year Tanks and Lower

The Commission intends that substantial emissions reductions be achieved from condensate storage tanks and that industry retain the flexibility to decide which tanks to control in order to achieve those reductions. The rule has been revised to subject any condensate storage tank to this rule in the Applicability Section, but stipulates in the Emission Control Section that in order to determine the appropriate system-wide emissions reductions, only two tons per year tanks be considered. In doing this, the Commission intends that tanks that emit actual uncontrolled volatile organic compound emissions of two tons per year or more be considered in determining compliance with the system-wide emissions reductions for the specific ozone non-attainment or attainment maintenance area, and that industry have the flexibility to control smaller tanks in those specific ozone non-attainment or attainment maintenance areas if needed in order to meet the applicable system-wide emissions reductions. For example, if a company owns 20 tanks that emit actual uncontrolled volatile organic compound emissions of two tons per year in a specific ozone non-attainment area, and 15 tanks that emit less than two tons per year, the company would determine its required emission reductions of the production through the 20 two tpy tanks, but be able to control any of the 15 additional less than 2 tpy tanks in order to comply with the system-wide emissions reduction or maintain the desired over control as buffer. However, all tanks controlled in order to comply with the system-wide emissions reduction standard must have filed an APEN and obtained a valid permit in order to be considered as part of the compliance demonstration.

Calendar Weekly and Calendar Monthly Records and Reports

The Commission intends that records and associated reports demonstrating compliance with the weekly emission reduction requirement shall start with the calendar week containing May 1st and end with the calendar week containing September 30th, or other specified dates in the rule. A calendar week begins midnight Sunday morning and ends the following Saturday evening at midnight. Thus, where May 1st falls on any day other than Sunday, the calendar week of May 1st begins on midnight of the preceding Sunday morning. Similarly, the weekly emission reduction requirement applies to the full calendar week that includes September 30th.

So, if September 30th falls somewhere in the middle of a calendar week, the emissions reduction requirement applies to that calendar week in full, beginning midnight Sunday morning and ending the following Saturday evening at midnight.

Consequently, calendar monthly records and associated reports demonstrating compliance with the monthly emission reduction requirement shall apply to midnight the morning of day 1 through midnight the evening of the last day of each specific calendar month.

The Commission intentionally broadened the definition of surveillance to provide that: 1) electronic surveillance is not specifically required, and other means to gather information from remote locations is allowed; and 2) data only had to be gathered on a daily basis. The Commission intends that currently required surveillance need only monitor combustion device flame presence or temperature once every day, in order to balance the need to gather adequate data on combustion device operation with the amount of data to be gathered, handled and processed. The Commission believes this is a fair approach considering that only the largest atmospheric condensate storage tanks (those with actual uncontrolled volatile organic compound emissions equal to or greater than 100 tons per year) are subject to this surveillance requirement.

Finally, the Commission intends that the monitoring be completed to ensure compliance, and has determined that failing to monitor as required, losing monitoring data, and failing to maintain monitoring data should be treated similarly to recordkeeping requirements. Thus, these actions "may be treated by the Division as if the data were not collected."

The Commission intends that system-wide emissions control requirements apply to each specific ozone non-attainment or attainment maintenance area and not collectively to all ozone non-attainment or attainment maintenance areas state-wide. This means that the system-wide emissions control requirements apply specifically to the Ozone Control Area (a.k.a. the Denver Metropolitan Area/North Front Range Ozone Control Area), separately from any future designated ozone non-attainment area. Each new ozone non-attainment area designated in the future shall be subject to the system-wide control requirements by themselves. This is needed to ensure that necessary controls are achieved and maintained in each ozone non-attainment or attainment maintenance area, and that these controls are not removed and offset by system-wide controls in some other ozone non-attainment area.

Pneumatics Emissions Control

This revision establishes new VOC controls for pneumatic controllers in the 8-hour Ozone NAA in Regulation Number 7, Section XVIII. Pneumatic controllers are widely used in the oil and gas industry to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow and temperature. Pneumatic controllers of interest are instruments that are actuated using natural gas pressure (of which some natural gas may be bled to the atmosphere from the pneumatic controller and some may be vented from the associated valve). Natural gas-actuated pressure relief devices are not intended to be covered by this rule. There are high-bleed controllers designed to emit more than six standard cubic feet of gas per hour (scfh) to the atmosphere, and low-bleed controllers that emit six scfh or less. Historically, high-bleed controllers have been used.

A 2003 EPA study reported that emissions from pneumatic controllers are collectively one of the largest sources of methane emissions in the natural gas industry. Estimated annual nationwide methane emissions are approximately 31 billion cubic feet (Bcf) from the production sector, 16 Bcf from the processing sector, and 14 Bcf from the transmission sector. As stated, by definition, high-bleed pneumatic controllers emit more than six scfh of natural gas to the atmosphere. The highest bleed rate listed in one source, a table published by the EPA, is 42 cubic feet per hour (cfh). The average bleed rate for high-bleed pneumatic controllers in the NAA is 21 cfh. Natural gas is primarily composed of methane, but also contains other compounds including VOCs and hazardous air pollutants (HAPs).

VOC emissions from pneumatic controllers within the NAA were 24.8 tons per day (tpd) for the 2006 baseline and have been projected to be 31.1 tpd for the 2010 baseline. These emissions represent 14.0

and 15.1 percent of the total VOC emissions from oil and gas sources in the NAA in 2006 and 2010, respectively. Therefore, emission reductions related to this source category have the potential to be significant.

These rules require that most high-bleed controllers must be replaced with the equivalent of low-bleed or better pneumatic controllers by May 1, 2009. There is an exception that allows high-bleed controllers that the Division agrees are necessary for safety purposes. Operators must inspect and maintain in-use high-bleed controllers on a monthly basis. Operators must also keep logs of the number of in-use high-bleed controllers, as well as the reasoning that high-bleed controller remains in place, and the inspection and maintenance of the in-use high-bleed controllers. These revisions further require operators to physically tag the in-use high-bleed controllers to enable the Division to track compliance.

The oil and gas industry has already begun replacing high-bleed controllers with low-bleed controllers, understanding the financial gain of minimizing the bleed rate of pneumatic controllers.

RICE Controls

Reciprocating internal combustion engine (RICE) requirements of Regulation Number 7, Section XVI, applies in what was the early action compact area (now the Ozone NAA). These revisions extend the RICE requirements' applicability to a state-wide basis.

Expand and Clarify RACT Requirements

Regulation Number 7 is revised to expand its application to all subject sources in any Ozone NAA and Attainment/Maintenance Areas. This previously applied to the one-hour attainment/maintenance area nonattainment area. Accordingly, this regulation will apply to some sources that were previously outside of its geographic scope. It is intended that existing sources become subject to previously adopted Control Technique Guidelines (CTGS) or general RACT requirements, and are given time to comply to implement the general RACT requirements. Specifically, existing sources that have not been modified are allowed three years from the date of ozone non-attainment designation to implement general RACT requirements. All new or modified sources become subject to these general RACT requirements upon commencing operation after the new ozone non-attainment designation date. This revision is considered a measured approach to ensuring the consistent use of best practices across the NAA as well as reductions in ozone precursors considered necessary to attaining the 8-hour ozone standard.

This revision expands Regulation Number 7's applicability to any Ozone NAA or attainment/maintenance area. This is done intentionally to apply Regulation Number 7 requirements to current as well as any future Ozone NAA or attainment maintenance areas in Colorado.

Additionally, this revision clarifies how the Regulation Number 3 RACT requirements interact with Regulation Number 7. This revision specifies that pursuant to Regulation Number 7, Section II.C. all existing sources that emit 100 tons per year of VOC emissions and that are located in the 8-hour Ozone NAA become subject to RACT.

Further, Regulation Number 7 is currently unclear on whether or not existing sources that are modified become subject to new source requirements. This revision clarifies that existing sources that are modified are subject to the Regulation Number 3, Part B, Section II.D. requirements and are considered to be a new source for the purposes of Regulation Number 7.

This revision also clarifies that the both case-by-case and general RACT requirements of Regulation Number 7, Section II.C. only apply to existing, new and modified sources. For sources at which all air pollution generating activities at that source are already subject to RACT or BACT, the RACT analysis would show that all activities are already subject to RACT or BACT. For any other air pollution generating activities not covered by RACT or BACT, the source would only have to complete a RACT analysis specific to those activities.

Typographical, Grammatical, Formatting and Other Changes

The commission changed the title of Regulation Number 7 to include NOx. An outline of the sections is provided to better understand the contents of Regulation Number 7. Outdated sections are removed (i.e. Section II.F.1. specific to Gates Rubber Company, which is now out of business). Section XII., specific to condensate tanks in the Ozone NAA is reorganized for clarity. One appendix (new Appendix A) is added to provide maps of Ozone NAAs and chronologies of attainment designations, of which certain requirements key off. Finally, sections and appendices are renumbered and formatted as necessary.

Section 110.5 and 110.8 Analysis

Some of these revisions are not intended to be incorporated into Colorado's SIP. To the extent these revisions could be construed to exceed the requirements of federal law, the Commission provides the following additional statement, consistent with C.R.S. § 25-7-110.5(5)(a):

- (I) These rules are intended to reduce uncontrolled emissions of ozone precursor pollutants. The rules thereby serve to attain and maintain compliance with the National Ambient Air Quality Standard (NAAQS) for Ozone. However, there are no comparable federal requirements that apply to the sources in question.
- (II) There are no applicable federal requirements, other than the duty to attain the ozone NAAQS. There is considerable flexibility in meeting the NAAQS. However, there are very limited sources of uncontrolled anthropogenic ozone precursor emissions to target in order to reduce ozone. Consequently, the sources in question, as a significant source of uncontrolled VOCs and NOx, must be targeted in order to attain the standard.
- (III) There are no applicable federal requirements, other than the duty to attain the ozone NAAQS. The ozone NAAQS was not determined taking into account concerns that are unique to Colorado.
- (IV) These rules may prevent or reduce the need for costly retrofit to meet more stringent requirements at a later date. The DMA/NFR non-attainment area has violated the 0.08 ppm ozone NAAQS. Colorado will soon be required to comply with the new ozone NAAQS of 0.075 ppm. Colorado Governor Ritter has directed that Colorado air quality planning agencies implement measures to reduce ozone to a level below the NAAQS. If these rules are not adopted now, it may be necessary to require costlier retrofitting in order to meet the Governor's directive as well as the new NAAQS.
- (V) Since there are no applicable federal requirements, there is no timing issue with regard to implementing federal requirements. However, these controls are intended to help the DMA/NFR attain the NAAQS. If the standard is not attained by the 2010 ozone season, the area may face a "moderate" non-attainment designation.
- (VI) The adopted rules will assist in establishing and maintaining a reasonable margin for accommodation of uncertainty and future growth.
- (VII) The adopted rules establish reasonable equity for sources subject to the rules by providing the same standards for similarly situated sources.

- (VIII) If the state rules were not adopted, other sectors may face a disproportionate share of the burden of reducing precursor pollutants.
- (IX) There are no corresponding federal requirements.
- (X) Demonstrated technology is available to comply. Sources are already using the control devices intended to be used to comply with these rules. However, sources face an additional burden of implementing auto-igniters and surveillance. The Commission anticipates a reasonable degree of delay in securing and installing the technology in question and has accommodated the sources by providing for a reasonable delay for the application of these requirements.
- (XI) The adopted rules will reduce VOC and NOx emissions, thereby contributing to the prevention of the formation of ozone through the most cost-effective means available.
- (XII) Alternative rules requiring additional controls for other sources would also provide gains toward attaining the ozone NAAQS. However, oil and gas industry members are the largest anthropogenic stationary source of precursor pollutants in the State. A disproportionate benefit to this industry would accrue if their uncontrolled emissions remain at current levels compared to other stationary sources.
- (XIII) A no-action alternative may address the ozone NAAQS. Modeling and other analysis suggests that the NAA would attain the standard by 2010 without these rules. However, this analysis suggests that ambient levels of ozone would be very close to the NAAQS. These rules provide more assurance of attaining the ozone NAAQS while also providing for reductions that are necessary to make progress toward the new ozone NAAQS. No action would only delay the necessary reductions.

Further, pursuant to C.R.S. § 25-7-110.8(1), the Commission makes the determination that:

- (I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.
- (II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of ground-level ozone.
- (III) Evidence in this record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.
- (IV) The rules are the most cost effective, provide the regulated community flexibility, and achieve any necessary reduction in air pollution.
- (V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

L. January 7, 2011 (Outline and Sections I. and XVII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedures Act, Section 24-4-103, C.R.S., and the Colorado Air Pollution Prevention and Control Act, Sections 25-7-110 and 25-7-110.5, C.R.S (the Act).

Specific Statutory Authority

The Colorado Air Quality Control Commission (Commission) promulgates this regulation pursuant to the authority granted in Sections 25-7-105(1)(c), C.R.S. (authority to adopt a prevention of significant deterioration program); 25-7-109(1)(a) (authority to require the use of air pollution controls); 25-7-109(2)(a) (authority to adopt emission control regulations pertaining to visible pollutants); and 25-7-114.4(1) (authority to adopt rules for the administration of permits).

Basis and Purpose

The Commission intends that the current Regulation Number 7, Section XVII.E.3.a. identifying technology-based control requirements for existing rich burn reciprocating internal combustion engines (RICE), or rich burn RICE that were constructed or modified prior to February 1, 2009, become a NO_x emission control measure that is included as part of the Regional Haze SIP and become federally enforceable upon EPA approval.

The technology-based control requirements of Section XVII.E.3.a. reduce NO_x. This proposal only changes the enforceability of these currently state-only requirements such that they become federally enforceable. This proposal does not change emission control, monitoring, recordkeeping or reporting requirements.

The Commission also intends that the following provisions, added in Sections XVII.E.3.a.(i)(a) through (c), will continue to be effective under the Regional Haze SIP. Specifically, these provisions require good air pollution control practices and allow for exemptions from the requirements for existing rich burn RICE. The exemptions apply to any existing rich burn RICE either with uncontrolled actual emissions below permitting thresholds or that is subject to a New Source Performance Standard (NSPS), National Emission Standard for Hazardous Air Pollutants (NESHAP), or Best Available Control Technology (BACT) limit.

Existing lean burn RICE requirements are not incorporated into the Regional Haze SIP, as the associated controls do not reduce NO_x or SO₂.

Colorado has determined that it is reasonable and appropriate to make these RICE requirements federally enforceable in this first planning period, as part of the state's strategy for addressing reasonable progress towards achieving natural visibility conditions in federal Class I areas.

M. December 20, 2012 (Sections II., XII., and XVII.)

This Statement of Basis, Specific Statutory Authority and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), Colorado Revised Statutes (C.R.S.) for new and revised regulations.

Basis

Regulation Number 7 is designed to implement substantive regulatory programs authorized under the Colorado Air Pollution Prevention and Control Act (Act) including provisions of the State Implementation Plan (SIP) addressed in C.R.S. Section 25-7-105(1)(a), emission control regulations addressed in C.R.S. Section 25-7-105(1)(b) and authorization of the development of a program for the attainment and maintenance of the National Ambient Air Quality Standards (NAAQS) in C.R.S. Section 25-7-301, as well as other authorized programs under the Act. The current revisions have been promulgated in order to facilitate this goal. The revisions were made to address the U.S. Environmental Protection Agency's ("EPA") partial disapproval of Colorado's ozone SIP.

On August 5, 2011, EPA published the “Approval and Promulgation of State Implementation Plans; State of Colorado; Attainment Demonstration for the 1997 8-Hour Ozone Standard, and Approval of Related Revisions” (76 Fed. Reg. 47443, August 5, 2011). EPA partially approved and partially disapproved revisions to Colorado’s SIP adopted by the Air Quality Control Commission (Commission) in December 2008 and submitted to the EPA in June 2009.

Statutory Authority

The statutory authority for these revisions is set forth in the Colorado Air Pollution Prevention and Control Act, C.R.S. Section 25-7-101, et seq., specifically, C.R.S. Section 25-7-105(12) (authorizing rules necessary to implement the provisions of the emission notice and construction permit programs and the minimum elements of the operating permit program), 109(1)(a), (2) and (3) (authorizing rules requiring effective practical air pollution controls for significant sources and categories of sources, including rules pertaining to nitrogen oxides and hydrocarbons, photochemical substances, as well as rules pertaining to the storage and transfer of petroleum products and any other VOCs), and Section 25-7-301 (authorizing the development of a program for the attainment and maintenance of the NAAQS).

Purpose

The Commission revised Regulation Number 7 to address the EPA’s partial disapproval of Colorado’s Ozone State Implementation Plan (“SIP”). On August 5, 2011, the EPA issued a final action on Colorado’s June 2009, Ozone SIP submittal, both approving Colorado’s attainment demonstration for the 1997 8-Hour Ozone National Ambient Air Quality Standard (NAAQS) and disapproving specific revisions to Regulation Number 7. 76 Fed. Reg. 47443, August 5, 2011. Specifically, the EPA disapproved both the repeal of Regulation Number 7, Section II.D. and all revisions to Section XII. as adopted by the Commission in December 2008. As a basis for its action, the EPA stated that Colorado demonstrated attainment with the 1997 8-Hour Ozone NAAQS, however Colorado did not adequately provide an anti-backsliding demonstration for the revisions to Regulation Number 7 that were adopted by the AQCC in December 2008, and submitted to the EPA in June 2009.

The Commission intends that these 2012 revisions include both SIP and state-only revisions that address EPA’s partial disapproval of SIP provisions in Sections II.D and XII., and make related state-only revisions to Section XVII. for consistency.

The Commission does not intend that these 2012 revisions add or strengthen emissions control measures of Section II.D., XII. or XVII. at this time. All SIP revisions are intended to specifically address those provisions that EPA included as part of its basis for disapproving revisions to Regulation Number 7.

While the EPA indicated general approval of the concept of the June 2009 SIP submittal, the EPA took exception to some of the details in the SIP revisions, characterized as “deficiencies,” that formed the basis of EPA’s disapproval during the SIP review process. EPA’s objections to the 2009 SIP revisions and the Commission’s responses are summarized as follows:

1. Section II.D. – Alternative Control Plans and Test Methods

EPA Objection: The EPA objected to the deletion of SIP approved language, allowing for alternative control plans and testing methods.

Commission Response: The Commission reinstated the SIP approved language.

2. Section XII.C.2. – Emission Factor Calculation Methodology for Condensate Tanks

EPA Objection: The EPA objected to the deletion of the term “gas-condensate-glycol separators” from the emission factor requirements for atmospheric condensate tanks.

Commission Response: The Commission made no revision to the rule text, and instead explained to EPA that this term was used in error as such a separator does not exist. The term used here is a misnomer, which the Commission believes refers to a flash tank located on a glycol dehydration unit, covered by Section XII.H. It is inappropriate to apply emission factor calculation methodology for atmospheric condensate tanks to glycol dehydrators because their emissions vary greatly.

3. Section XII.D.2.a. – System-wide Control Requirements for Condensate Tanks

EPA Objection: The EPA objected to the sunset of the system-wide control requirement in Section XII.D.2.a.(x), which ended the control requirement as of April 30, 2013.

Commission Response: The Commission revised the system-wide control requirements so that the system-wide control requirements do not sunset. Neither the Commission nor the parties to the December 2008 rulemaking intended for the system-wide control to end. The sunset was unintentionally caused when making other revisions to the rule text.

4. Section XII.E.3. – Monitoring Combustion Devices as Control for Condensate Tanks

EPA Objection: The EPA objected to providing a state-only monitoring option (electronic surveillance) as a substitution for the SIP required monitoring of combustion devices being used to control emissions from condensate tanks in accordance with Section XII.

Commission Response: The Commission removed the option of conducting state-only electronic monitoring in lieu of the SIP approved monitoring requirement. This allowance to substitute a SIP required monitoring provision for a state-only monitoring provision was unintentional. None of the sources employing electronic surveillance may use it in place of the SIP approved requirement. If conducted, the electronic surveillance monitoring option must occur in addition to the SIP approved monitoring requirement.

5. Section XII.F.3. – Recordkeeping for Condensate Tanks

EPA Objection: The EPA objected to the lack of SIP required recordkeeping for the control requirement in Section XII.D.1., which requires all condensate tanks at exploration and production sites to be controlled during the first 90 days of well production.

Commission Response: The Commission revised Section XII.D.1. to specify it is state-only. The Commission and parties to the December 2008 rulemaking intended for this first 90-day control requirement to be state-only, which corresponds to the state-only designation on the recordkeeping requirements under Section XII.F.3. Therefore, the Commission made no revision to Section XII.F.3., and instead revised Section XII.D.1. to alleviate this discrepancy.

6. Section XII.F.5. – Recordkeeping and Reporting Exemption for Compressor Stations and Drip Stations

EPA Objection: The EPA objected to the removal of a SIP approved provision that exempted natural gas compressors or drip stations from recordkeeping and reporting requirements, where total emissions from such facilities are less than 30 tons per year.

Commission Response: The Commission reinstated the SIP approved 30 tons per year provision.

7. Section XII.G.2. – Control Equipment Requirement for Natural Gas Processing Plants

EPA Objection: The EPA objected to two aspects of the revisions to this section. The first objection was replacement of the term “APEN de minimus levels” with “greater than or equal to two tons per year.” The second objection was inclusion of a rolling 12-month averaging period for the 95% control requirement.

Commission Response: The Commission made no revision to the replacement of the term “APEN de minimus levels.” The Commission explained to the EPA that the associated modeling relied on evaluating condensate tanks with emissions greater than or equal to two tons of volatile organic compounds per year. Therefore, the change in reference does not constitute a lessening of the stringency of the rule. In addition, the Commission removed the rolling 12-month averaging period.

8. Section XII.G.5. Recordkeeping and Reporting for Alternative Compliance Option

EPA Objection: The EPA objected to the reliance on Title V or construction permits as the location for recordkeeping and reporting requirements for condensate tanks at natural gas compressor or drip stations.

Commission Response: The Commission revised this section to specify recordkeeping and reporting requirements for condensate tanks at natural gas compressor and drip stations.

9. Section XII.H. Control Requirements for Glycol Dehydrators

EPA Objection: The EPA stated this entire section lacked clarity and contained redundant language.

Commission Response: The Commission revised the section in its entirety, while maintaining the intent and applicability of the requirements. Along with this revision, the Commission specified that this control requirement is applicable only to glycol dehydrators with emissions equal to or greater than one ton per year, but that all glycol dehydrators at a stationary source must be included for comparison to the 15 ton per year threshold. The term stationary source is defined in the Common Provisions. Further, the Commission revised the provision to include emission calculation methodology requirements in Section XII. H.

Items 1-9 are all SIP revisions.

In addition, the Commission is also revising the state-only Section XVII.D. for consistency with the 2012 SIP revisions. The Commission does not intend that this state-only revision change the applicability of the control requirements for glycol natural gas dehydrators. Finally, the Commission made typographical, grammatical, and formatting revisions, as necessary.

N. February 23, 2014 (Sections II., XVII., and XVIII.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

On October 18, 2012, the Commission partially adopted federal Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution found in 40 CFR Part 60, Subpart OOOO ("NSPS OOOO") into Regulation Number 6, Part A. During the partial adoption of NSPS OOOO, the Commission requested the Air Pollution Control Division ("Division") to consider full adoption at a later date and directed the Division to identify additional oil and gas control measures that complement and expand upon NSPS OOOO. This rulemaking is the result and further addresses the volatile organic compound ("VOC"), an ozone precursor, and other hydrocarbon emissions, such as methane, from the oil and gas sector.

The Commission supports the EPA's development of NSPS OOOO and believes that additional hydrocarbon control measures are warranted in Colorado for several reasons. First, the Denver Metropolitan Area/North Front Range is in nonattainment with EPA's current 8-Hour Ozone National Ambient Air Quality Standard ("NAAQS"); it is likely that EPA will lower the ozone NAAQS in the near future, potentially expanding Colorado's nonattainment area; and Division air monitors and other sampling indicate elevated levels of oil and gas related air emissions in oil and gas development areas. Second, Colorado has seen substantial growth of oil and gas development in recent years, which is a significant source of VOC emissions, and expects that growth to continue in the foreseeable future. In particular, oil and gas storage tanks contribute significantly to the VOC emissions from oil and gas development. Further, oil and gas operations also emit methane, a negligibly reactive ozone precursor and potent greenhouse gas. Third, oil and gas operators have had difficulty meeting the current 95% control requirements in Regulation Number 7 established for condensate tanks in 2004 and 2006 due to "flash" emissions. Fourth, improved technologies and business practices, many already utilized by Colorado oil and gas operators, can reduce emissions of hydrocarbons such as VOCs and methane in a cost-effective manner. These technologies and practices include, without limitation, auto-igniters, low- or no-bleed pneumatic controllers, stabilized liquids or reduced tank pressures, flares achieving at least 98% destruction efficiency, and leak detection and repair (including the use of infrared ("IR") cameras).

For these reasons and more, the Commission believes additional control measures beyond the current requirements in Regulation Number 7 and NSPS OOOO are appropriate. Colorado's considerable experience with the regulation of oil and gas sources involves both SIP and state-only requirements. During the rulemaking process, various parties provided extensive evidence concerning whether the proposed revisions, in particular the STEM and LDAR requirements, should apply either statewide or only in the ozone nonattainment area. Based upon careful consideration of all the evidence provided during the rulemaking, the Commission determined it was appropriate to apply the proposed requirements statewide. Further, in addition to the extensive evidence concerning the benefits of statewide hydrocarbon emission reductions, the Commission believes that the tiered and phased nature of many of the requirements properly focuses on emissions. Under this tiered approach, lower emitting sources such as marginal, stripper, and coal bed methane wells will appropriately be subject to less rigorous and costly requirements. In addition, evidence in the rulemaking record and testimony of industry members supports the conclusion that the rules can be effectively implemented. Accordingly, the Commission concludes that the proposed rules are technologically feasible and cost-effective. Moreover, because these revisions apply on a state-wide, state-only basis, and are not a part of Colorado's SIP, the Commission, the Division, and stakeholders have the opportunity to further assess the implementation and effectiveness of these requirements, to better inform future actions.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., (“Act”), C.R.S. § 25-7-105(1) directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in Section 25-7-102 and are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant and provides the Commission broad authority to regulate air pollutants. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Sections 25-7-109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons.

Purpose

The following section sets forth the Commission’s purpose in adopting the revisions to Regulation Number 7, and includes the technological and scientific rational for the adoption of the revisions. The Commission adopts revisions to Regulation Number 7 to address hydrocarbon emissions from oil and gas facilities, including well production facilities and natural gas compressor stations. The Commission expands existing oil and gas control requirements and establishes additional monitoring, recordkeeping, and reporting requirements. For example, the revisions increase control requirements and improve capture efficiency requirements for oil and gas storage tanks. The Commission also seeks to minimize fugitive emissions from leaking components at natural gas compressor stations and well production facilities. Further, the Commission intends to minimize emissions at new and modified oil and gas wells and wells undergoing maintenance and during liquids unloading events. The Commission also expands control requirements for pneumatic devices and glycol natural gas dehydrators. The Commission believes that this combination of revisions is appropriate to complement the full adoption of NSPS OOOO, and to further reduce emissions produced by the oil and gas industry.

Among other things, these revisions:

- Expressly address hydrocarbon emissions in Section XVII. and XVIII.;
- Amend definitions in Section XVII.A. and XVIII.B.;
- Strengthen good air pollution control practices, require use of auto-igniters, remove the off-ramp for condensate tanks if subject to a NSPS, MACT, or BACT, and remove the leak detection and repair requirements off-ramp for glycol natural gas dehydrators and internal combustion engines if subject to a NSPS, MACT, or BACT in Section XVII.B.;
- Expand condensate tank control requirements to apply state-wide, to all hydrocarbon liquid storage tanks, and to smaller storage tanks in Section XVII.C.;
- Limit venting and establish a storage tank emissions monitoring system (“STEM”), and associated recordkeeping and reporting requirements in Section XVII.C.;
- Expand glycol natural gas dehydrator control requirements in Section XVII.D.;
- Establish a leak detection and repair program for natural gas compressor stations and well production facilities in Section XVII.F.;

- Establish control measures for oil and gas wells in Section XVII.G.;
- Limit venting during well maintenance and liquids unloading in Section XVII.H.; and
- Expand pneumatic device requirements in Section XVIII.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Joint Applicability of NSPS OOOO and Regulation Number 7, Sections XII. and XVII.

It is possible for storage tanks to be subject to NSPS OOOO and Regulation Number 7, Sections XII. and XVII. While this creates some overlap between the different requirements, the requirements secure different emissions reductions. Regulation Number 7, Section XII. applies to condensate storage tanks in the 8-Hour Ozone Nonattainment Area, whereas NSPS OOOO applies to storage vessels that contain more than just condensate, such as produced water and crude oil. NSPS OOOO also applies to individual storage vessels, whereas Regulation Number 7, Sections XII. and XVII. apply to single tanks and, if manifolded together, the series of tanks in tank batteries. In addition, NSPS OOOO applies to storage vessels with six (6) tons per year ("tpy") of controlled actual VOC emissions, whereas Regulation Number 7, Sections XII. and XVII. base applicability on uncontrolled actual emissions. For these reasons, and considering that portions of Regulation Number 7, Section XII. are approved in Colorado's SIP, the Commission intends for the federal and state rules to jointly apply to storage tanks in Colorado.

Furthermore, because NSPS OOOO allows oil and gas operators to avoid applicability by establishing enforceable emission limits below NSPS OOOO applicability thresholds through a state, federal, or local requirement, most storage tanks subject to Regulation Number 7 will not be subject to NSPS OOOO monitoring or recordkeeping requirements. It is the Commission's intent that compliance with Regulation Number 7, Sections XII. and XVII. shall serve to establish legally and practically enforceable limits for the purpose of estimating emissions from storage vessels under NSPS OOOO. In those limited cases where storage tanks are subject to both NSPS OOOO and Regulation Number 7 control requirements, Regulation Number 7 will require some additional emissions monitoring. However, joint applicability is anticipated to be limited to those storage tanks whose uncontrolled actual VOC emissions are one hundred and twenty (120) tpy, the equivalent of the NSPS OOOO six (6) tpy VOC on a controlled actual basis. While this means that more storage tanks are regulated under Regulation Number 7, Section XVII., they are regulated on a state-only basis, and are not federally enforceable like NSPS OOOO. Thus, the Commission believes joint applicability is necessary and intentionally removed storage tanks from the exemption in Section XVII.B.4. that allowed sources subject to an NSPS, MACT, or BACT control requirement to avoid having to comply with Section XVII.

It is also possible for glycol natural gas dehydrators and internal combustion engines to be subject to both federal and Regulation Number 7, Section XVII. leak detection and repair requirements. NESHAP HH and HHH require glycol natural gas dehydrators at major sources of hazardous air pollutants ("HAP") that utilize a closed-vent system to conduct annual visual inspections for leaks and defects that could result in air emissions. NESHAP HH and HHH also require detected leaks and defects be repaired within fifteen days, as long as it is technically feasible to do so without a shutdown. NESHAP HH also requires triethylene glycol ("TEG") natural gas dehydrators located at area sources of HAPs that utilize a closed-vent system to conduct annual visual inspections. However, the revisions to Regulation Number 7 require more frequent inspections of all types of glycol natural gas dehydrators at all facilities, resulting in more emissions reductions than NESHAP HH and HHH. Therefore, the Commission believes joint applicability concerning leak detection and repair requirements is necessary.

Applicability of Parts of Regulation Number 7 to Hydrocarbons

Many of the control measures set forth in these revisions have the benefit of reducing both VOC and other hydrocarbon emissions, such as methane. Sections XVII. and XVIII. have been revised to reflect the Commission's intent that the provisions contained therein reduce emissions of the broader category of hydrocarbons.

Visible Emissions

Regulation Number 7, Sections XII. and XVII. have historically contained a prohibition on visible emissions from combustion devices, such as flares. The Commission is not proposing to relax this requirement. To address comments from diverse stakeholders, the Commission is clarifying how Division inspectors and the regulated community are to determine compliance with the prohibition on visible emissions. The Commission has qualified that visible emissions are emissions of smoke that are observed for a period in duration of greater than or equal to one (1) minute during a fifteen (15) minute time period, pursuant to EPA Method 22. The Commission expects that both Division inspectors and the regulated community will, if any smoke is observed, determine whether the emissions are considered visible emissions for purposes of Regulation Number 7. The regulated community may, alternatively, immediately shut-in the equipment to investigate the cause for smoke and perform repairs. While the presence of visible emissions constitutes a violation of the rules, the Commission recognizes that there may be instances where visible emissions occur notwithstanding the owner or operator's best efforts, such as when an upset or malfunction occurs. Accordingly, the Division should consider the owner or operator's efforts and whether the visible emissions resulted from factors outside the owner or operator's control in determining how to best enforce this requirement.

Definitions (Section XVII.A.)

The Commission has revised or added definitions for several terms. Further explanation for a few of these terms is set forth below.

"Approved instrument monitoring method" ("AIMM") means the methods and technologies utilized for monitoring storage tanks and components at well production facilities and natural gas compressor stations. The instrument being used for AIMM inspections must be capable of measuring hydrocarbon compounds at the applicable leak definition concentration specified in the revisions, and calibrated as appropriate. See EPA Method 21 at 6.0. In addition, while the definition lists EPA Method 21 and IR cameras, the Commission does not intend to limit industry to only EPA Method 21 and IR cameras as the Division may approve the use of additional monitoring devices and methods.

"Component" excludes compressor seals and open-ended valves and lines, which are defined separately, because they are designed to leak and are better addressed with equipment specific work practices, also included separately. Based on concerns that the requirements for small reciprocating compressors at well production facilities may not be cost-effective, the adopted work practices for reciprocating compressors are limited to reciprocating compressors located at natural gas compressor stations. Nevertheless, there is an issue as to whether compressors at well production facilities are a significant source of emissions. The Commission, therefore, directs the Division to investigate whether reciprocating compressors at well production facilities are a significant source of emissions, and if so, whether there may be appropriate, cost-effective work practices to reduce fugitive emissions from reciprocating compressors at well production facilities. The Commission further directs the Division to brief the Commission on this investigation in March, 2015.

"Date of first production" is meant to coincide with the date reported to the Colorado Oil and Gas Conservation Commission's ("COGCC") as the "date of first production," as currently used in COGCC Form 5A. The Commission intends for oil and gas sources to use only one date for compliance with both COGCC and Commission requirements.

“Natural gas compressor stations” are subject to leak detection and repair requirements. This definition is meant to exclude compressors at well production facilities and gas processing plants. This definition is also meant to exclude natural gas compressor stations that are downstream of the natural gas processing plant at this time.

“Normal operation” is considered to include all operation, including maintenance and other activities, as long as the operation does not meet the definition of “malfunction” as set forth in the Common Provision regulations.

“Storage tank,” means a single storage tank or a storage tank battery if the storage tanks are manifolded together. In recent years, it has become more common for multiple storage tank batteries, sometimes containing different hydrocarbon liquids, to be manifolded at the emissions line and routed to a common control device. To further clarify the concept of manifolded within the definition of “storage tank,” the Commission revises the definition of storage tank to specify that a storage tank battery must be manifolded by liquid line, and not just by gas or emission line. This revision is in keeping with the rationale that a single tank could have been used to capture liquids in place of multiple small storage tanks in a battery. The Commission’s definition, and Colorado’s approach to emissions reporting and permitting for storage tanks, differs from EPA’s definition of “storage vessel” and the description of an affected storage vessel facility in NSPS OOOO because EPA considers each individual tank, even those in a battery manifolded by liquid line, to be a storage vessel for comparison against the applicability threshold. The Commission intends to maintain this distinction and, therefore, deletes the previously used definition of “atmospheric condensate storage tank” and creates a new definition of “storage tank” which expands upon the definition of storage vessel in NSPS OOOO to include storage vessels manifolded together by liquid line.

“Well production facilities” are also subject to leak detection and repair requirements and storage tank maintenance requirements. This definition is meant to include all of the emission points, as well as any other equipment and associated piping and components, owned, operated, or leased by the producer located at the same stationary source (a defined term specific to permitting). The “owned, operated, or leased” qualifier in the definition is not meant to reduce the stringency of LDAR requirements in situations where there are multiple owners or operators of the well production facility. This definition is meant to exclude natural gas compressor stations from “well production facility” and avoid overlapping LDAR requirements. This definition is also meant to exclude natural gas storage wells.

Good Air Pollution Control Practices (Section XVII.B.)

The Commission intends that all oil and gas operations, including those below control thresholds or even below Regulation Number 3 APEN and permitting thresholds, adhere to good general air pollution control practices. Examples of what the Commission considers to be a good air pollution control practice include, but are not limited to:

- Keeping the thief hatch, pressure relief valve, or other access point on storage tanks closed and properly sealed during normal operation, unless being actively used during periods of maintenance or liquids loadout from the storage tank;
- Inspecting and repairing seals on thief hatches, access points, or other openings of storage tanks;
- Initiating timely action to address leaks or unpermitted emissions; and
- Maintaining equipment and the facility in good operating condition.

Venting vs. Leaking (Sections XVII.B., XVII.C., and XVII.F.)

The Commission believes that emissions caused by over pressurization of oil and gas equipment are foreseeable, are not adequately addressed by NSPS OOOO, and should be addressed in Colorado specific regulations. The Commission intends these revisions to address venting emissions from storage tank thief hatches, pressure relief valves, or other access points during normal operations. Access points are not limited to points of entry of liquids or gas into the storage tank but include any route from which emissions can escape. The Commission recognizes that pressure release valves and other devices are meant to operate as safety devices and that venting for safety purposes may occur due to sudden, unavoidable equipment failures or surges beyond normal or usual activities that could not have been reasonably foreseeable, avoided, or planned. For example, an unplanned third party outage resulting in increased pressure along the system may be the type of malfunction or scenario where venting may be necessary for safety purposes. The Commission does not intend to increase risk or compromise safety of personnel and equipment. However, inadequate design of a storage tank emissions capture system is not a legitimate reason for venting.

Therefore, the Commission intends that the malfunction affirmative defense in the Common Provisions regulation continue to be available to owners or operators, provided that the owners or operators demonstrate that the elements of the malfunction defense have been met. The Commission intends that the burden remain on the owner or operator to demonstrate that an emission should not be considered venting as provided in Section XVII.C.2. The Commission further recognizes that meeting the no venting requirement may be challenging in some cases, and accordingly has adopted additional provisions requiring owners and operators to develop a STEM plan to help ensure compliance. In some cases, development and implementation of the STEM plan may be an iterative process involving ongoing improvements before continuous compliance with the no venting standard is achieved. With this in the mind, the Division should consider the efforts of owners and operators in developing and implementing their STEM plan as part of the Division's assessment about how best to enforce the no venting requirement.

In contrast with venting, leaking as used in Section XVII.F. more specifically relates to unintended emissions from components at well production facilities and natural gas compressor stations. Identification and repair of leaks in accordance with these revisions benefits the public, the environment, and the oil and gas industry. The Commission has determined that leaks discovered by the owner or operator or the Division inspector pursuant to the detection methods specified in Section XVII.F. shall not be subject to enforcement by the Division under certain circumstances. For example, if a leak is identified and the owner or operator is in the process of timely and properly addressing the leak in accordance with these revisions, the Division should afford the owner or operator the opportunity to fix the leak absent enforcement. However, by this provision, the Commission does not intend to exempt owners or operators from their obligation to operate without venting or to utilize good air pollution control practices at all times.

Storage Tanks Controls (Section XVII.C.)

EPA established a six (6) tpy VOC threshold on a controlled actual emissions basis for applying storage vessel controls. In contrast, Colorado uses the sum total emissions from a tank battery, where multiple tanks are manifolded together, on an uncontrolled actual emissions basis for applying reporting, permitting, and control requirements. This means that the EPA's six (6) tpy threshold on a controlled actual emissions basis applies to individual tanks having the equivalent of one hundred and twenty (120) tpy VOC on an uncontrolled actual basis. Thus, more storage tanks are regulated under Regulation Number 7, Section XVII. than under NSPS OOOO.

The Commission intends that under Regulation Number 7, Section XVII., air pollution control equipment may be removed if: (1) the storage tank (including manifolded tanks) emissions fall below the uncontrolled actual six (6) tpy threshold, on a rolling twelve-month basis; and (2) those controls are not required by other applicable requirements. Conversely, if storage tank emissions increase above the uncontrolled actual six (6) tpy threshold on a rolling twelve-month basis, air pollution control equipment must be installed within sixty (60) days of discovery of the increase.

The Commission does not intend for the storage tank control, or related, requirements to apply to frac tanks that are located at a well production facility for less than 180 consecutive days.

Control Efficiency (Section XVII.C.)

The Commission expands the 95% control efficiency requirement to apply to storage tanks containing any hydrocarbon liquids (including condensate, crude oil, produced water, and intermediate hydrocarbon liquids), for consistency with NSPS OOOO. Produced water and crude oil storage tanks, which in years past were thought to have insignificant emissions, can instead be significant sources of emissions. This rule change is also a result, in part, of the removal of the APEN exemption in 2008 for tanks containing crude oil and less than 1% crude. The Commission intends that the air pollution control equipment achieve an average hydrocarbon control efficiency of at least 95%, and if a combustion device is used the device must have a design destruction efficiency of at least 98%, with few exceptions. The Commission recognizes and expects that most flares can control hydrocarbon emissions by 98% or more when properly operated.

Audio, Visual, Olfactory ("AVO") and Visual Inspections (Section XVII.C.)

The Commission intends that owners and operators of subject storage tanks (including storage tanks during the first ninety (90) days of production and storage tanks containing only stabilized liquids) conduct applicable AVO and visual inspections for venting or leaking. Visual inspections are in addition to AVO monitoring and require further inspections of the storage tank and associated equipment, such as thief hatches and air pollution control equipment. These inspections are not required to occur at the same time as loadout. Instead, loadout triggers the requirement for AVO and visual inspection, and indicates the frequency at which inspection is required.

Storage Tank Emission Management System ("STEM") Plan, Monitoring, and Recordkeeping (Section XVII.C.)

Owners and operators of storage tanks with uncontrolled actual emissions equal to or greater than six (6) tpy must develop, certify, and implement a STEM plan designed to ensure compliance with the "without venting" requirement of Section XVII.C.2., among other requirements. Through STEM, owners and operators must evaluate and employ appropriate control technologies, monitoring, maintenance, and operational practices to avoid venting of emissions from storage tanks. The Commission intends that sources have flexibility to develop STEM plans on an individual basis for each storage tank or for multiple storage tanks. However, upon request, the owner or operator must be able to identify to the Division what STEM plan applies to a storage tank and make that plan available for review. Owners and operators of storage tanks controlled during the first ninety (90) days of production or containing only stabilized liquids are not required to develop and implement a STEM plan. However, owners or operators of such storage tanks must still comply with applicable control, capture, monitoring, and recordkeeping requirements.

For purposes of clarification, the STEM plan is intended to include, but is not limited to, the following elements:

- A monitoring strategy including, at a minimum, the applicable inspection frequencies and methodologies;

- An identification of the personnel conducting the monitoring, and any training program, materials, or training schedule for such personnel. This element does not require training, but ensures that any training be documented to permit the owner or operator to demonstrate the quality and achievements of the STEM plan;
- The calibration methodology and schedule for emission detection equipment used in the monitoring;
- An analysis of the engineering design of the storage tank and air pollution control equipment, and where applicable, the technological or operational methods employed to prevent venting;
- An identification of the procedures to be employed to evaluate ongoing capture performance after implementation of the STEM plan;
- A procedure to update the STEM plan when capture performance is not adequate, the STEM design is not operating properly, when otherwise desired by the owner or operator, or when required by the Division; and
- The certification made by the appropriate personnel with actual knowledge of the STEM design for each storage tank.

In addition to AVO and visual inspections for storage tanks, STEM plans must include AIMM inspections on a frequency schedule that is tied to the uncontrolled actual VOC emissions from the storage tank. The Commission intends that the AIMM inspection satisfy any simultaneous AVO and visual inspection requirement.

The STEM plan should be maintained by the owner or operator for the life of the storage tank, while records of applicable monitoring only need to be retained for a period of two years. Upon sale or transfer of ownership of a storage tank, the relevant documentation and records should be transferred with the ownership. Owners and operators are encouraged to reevaluate any existing STEM plan for the storage tank upon purchase or acquisition of the storage tank.

Unsafe, Difficult, or Inaccessible to Monitor (Sections XVII.C. and XVII.F.)

The Commission does not intend to require owners or operators to conduct either AVO or AIMM inspections of unsafe, difficult, or inaccessible components or storage tanks and associated equipment. The Commission acknowledges that, in limited circumstances, unsafe to monitor may include unsafe weather or travel conditions. However, in those limited circumstances, the Commission expects the owner or operator to resume monitoring once the weather or travel conditions cease to be unsafe. Importantly, the Commission does not intend to allow owners or operators to delay required monitoring for the entire winter season.

Glycol Natural Gas Dehydrators (Section XVII.D.)

The Commission expanded the state-wide control requirements for glycol natural gas dehydrators. This revision requires that all existing glycol natural gas dehydrators with uncontrolled actual VOC emissions of six (6) tpy or greater be controlled with air pollution control equipment achieving at least a 95% reduction. This revision also requires that existing glycol natural gas dehydrators with uncontrolled actual VOC emissions of two (2) tpy or greater be controlled if the dehydrator is located within 1,320 feet of a building unit or designated outside activity area. The definitions for building unit and designated outside activity area are taken from COGCC regulations.

The Commission does not intend to apply this proximity requirement to the glycol natural gas dehydrator owner or operator's buildings, where public access to the building is also restricted. Further, because glycol natural gas dehydrators are different and unique sources, a similar proximity requirement for storage tanks is not appropriate at this time as storage tanks are more appropriately addressed based on emission thresholds.

This revision also requires that all new glycol natural gas dehydrators with uncontrolled actual VOC emissions of two (2) tpy or greater be controlled with air pollution control equipment achieving at least 95% reduction. If a combustion device is used, it must have a design destruction efficiency of at least 98%, with few exceptions. The Commission recognizes and expects that most flares can control hydrocarbon emissions by 98% or more when properly operated.

Leak Detection and Repair Requirements (Section XVII.F.)

The Commission believes the detection and timely repair of leaks is important in the efforts to reduce hydrocarbon emissions. The use of appropriate inspection instruments and methods, such as IR cameras, enhances the detection and reduction of emissions. The leak detection and repair program more broadly targets leaks from components at natural gas compressor stations and well production facilities, even if such facilities do not include storage tanks. In contrast, STEM targets venting from storage tanks. The use of an AIMM as it relates to leak detection and repair frequency is generally intended to complement the STEM monitoring schedule. The Commission has created a phased schedule and tiered approach for leak detection and repair that is based on emissions, recognizing that smaller operators and facilities may have lower emissions and may need additional time to comply. Owners or operators have flexibility in how to meet the leak detection and repair requirements, including utilizing their own equipment and personnel or hiring a third party contractor. Owners or operators also have flexibility in timing the AVO and AIMM inspections to coordinate overlapping AVO and AIMM inspections, as well as inspections of facilities in the same area or on the same inspection frequency. The Commission intends that the AIMM inspection satisfy any simultaneous AVO inspection requirement. However, the Commission expects that owners and operators will also utilize this flexibility to ensure that inspections are appropriately spaced on the frequency schedule (e.g. quarterly inspections will occur every three months but not, for example, on March 31 and April 1).

The Commission distinguished between new and existing well production facilities by utilizing an October 1, 2014, commenced construction date and created an inspection phase-in schedule for existing facilities.

The Commission also distinguished the emissions thresholds for determining inspection frequencies for well production facilities with storage tanks and well production facilities without storage tanks. For well production facilities with storage tanks, the threshold determining inspection frequency is based on the uncontrolled actual VOC emissions from the highest emitting storage tank. For well production facilities without storage tanks, the threshold determining inspection frequency is based on "facility emissions." The Commission has determined that "facility emissions" means the controlled actual VOC emissions from all permanent equipment, including fugitive emissions calculated using the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates.

The Commission has defined a leak requiring repair in a manner that is dependent on the monitoring methodology. Leak detection methodologies have varied abilities to identify emission quantity and chemical makeup. EPA Method 21, for example, detects and quantifies hydrocarbon emission concentration, but does not speciate hydrocarbons (e.g., methane from other hydrocarbons) or identify the emission rate. Similarly, while IR cameras are becoming much more prevalent as a more affordable, time-saving, and user-friendly tool, they also do not speciate hydrocarbons or quantify the emission concentration. The Commission provides owners and operators flexibility in selecting a leak detection methodology.

If EPA Method 21 is utilized, the Commission set the threshold at which component leaks must be repaired at 2,000 parts per million ("ppm") hydrocarbons for existing natural gas compressor stations and

500 ppm for new (constructed after May 1, 2014) natural gas compressor stations and new and existing well production facilities. Where IR camera or AVO monitoring is utilized, a leak is any detectable emission not associated with normal equipment operation (e.g. the acceptable level of leaks from a component designed to leak). These values were determined based in part on a review of current federal or state leak detection and repair requirements for natural gas processing plants, refineries, and other oil and gas sources.

Leak detection values have decreased over time, in recognition of improved technologies and business practices. NSPS OOOO identifies leaks at natural gas processing plants at 500 ppm. Prior to NSPS OOOO, leaks were identified in other New Source Performance Standards (NSPS KKK and NSPS VVa) at 10,000 ppm. In addition, California, Wyoming, and Pennsylvania have varying leak detection and repair requirements and approaches to defining a leak. Some California air quality districts generally define a minor leak as between 1,000 and 10,000 ppm. Wyoming does not have a numerical limit. Pennsylvania essentially defines a leak at a well pad as anything with detectable emissions utilizing Method 21, as more than 2.5% methane or 500 ppm VOC, or no visible leaks using an IR camera. Upon consideration of all of the evidence presented, the Commission chose to define component leak at the foregoing thresholds.

The Commission expects that leaks that are not located specifically at a component will be addressed and repaired, in accordance with the general requirements to minimize emissions and employ good air pollution control practices. Further, the Commission finds that the repair deadlines set forth in Section XVII.F.7. provide flexibility for operational differences, including the potential range of leaks and degrees of repair difficulty that may be encountered.

The Commission anticipates that many operators will choose to utilize IR cameras, in light of their relative ease of use and increased reliance by both by industry and regulators within Colorado and across the country.

The Commission expects that owners and operators will remonitor leaks requiring repair with either the approved instrument monitoring method the owner or operator used to identify the leak or any method approved for remonitoring of leaks under EPA Method 21.

The Commission expects that in most instances the leak detection and repair requirements of this regulation will apply in lieu of leak detection and repair requirements in permits existing as of the promulgation date of the revisions. The Commission recognizes that leak detection and repair requirements in a few state permits may be federally enforceable, and this state-only regulation cannot supersede federal requirements. The Commission expects the Division and owners and operators to work cooperatively on the efficient implementation of leak detection and repair requirements, in those rare instances where there may be duplicative or competing requirements.

During the rulemaking, several parties requested more stringent requirements for all oil and gas operations located within 1,320 feet of a building unit or designated outside activity area. Residents living within close proximity to oil and gas operations, particularly those living within 1,320 feet of oil and gas operations, may understandably have heightened concerns regarding potential impacts of emissions from such facilities. It is the Commission's understanding that some oil and gas owners and operators implement practices beyond what is currently required under state law in order to minimize emissions and otherwise be good neighbors, including conducting increased site inspections. The Commission supports such practices.

Also during the rulemaking, various parties provided extensive evidence concerning the frequency of instrument monitoring method inspections, the timing of leak repair, and the costs and benefits associated with more or less frequent monitoring and repair. The Commission recognizes that additional information would benefit the Commission, Division, industry, and other stakeholders and therefore encourages the Division to work with energy companies, to evaluate the comparative effectiveness of various kinds of instrument based monitoring methods and program designs at a range of types, sizes, and frequencies at well production facilities and natural gas compressor stations.

The Commission also encourages the Division to work with industry and other stakeholders to evaluate emissions from and potential control strategies for downstream natural gas compressor stations and intermittent pneumatic controllers.

Lastly, several parties to the rulemaking requested greater transparency and public access to air quality information associated with oil and gas development. In particular, a coalition of local community organizations requested that owner and operators' annual reports as required by these rules be posted on the Division's website. The Commission believes these reports will provide important information when reviewing the efficacy of the inspection and maintenance program, as well as valuable information to interested citizens, particularly those who live in close proximity to oil and gas facilities. Therefore, the Commission requests that the Division make this information available in the most efficient means possible, which may include posting on the Division's website individual reports and/or a compilation summary. In addition, the Commission requests an annual briefing on these regulations. Such briefing will assist the Commission and interested stakeholders to understand the data and implementation issues relating to this new program, as well as other initiatives covered in this rulemaking. The Commission believes that this information would also be valuable to all parties.

Well Maintenance and Liquids Unloading (Section XVII.H.)

Over time, liquids build up inside a well and reduce flow out of the well. These liquids can slow and even block gas flow in wet gas wells and are removed during a well blowdown, also called liquids unloading. As a result of recent information, EPA has significantly increased their emission factor for liquids unloading. The uncontrolled emission factor is based upon fluid equilibrium calculations used to estimate the amount of gas needed to blow down a column of fluids blocking a well and Natural Gas STAR partner data on the amount of additional venting after a blowdown. Similar to the issues with well maintenance and well completion emissions, considerable uncertainty for liquid unloading emissions arises from the limited data sources used and the applicability of Natural Gas STAR program activities to calculate industry baseline emissions. This is especially important as liquid unloading emissions are estimated to comprise 33% of the uncontrolled methane emissions from the natural gas industry in the latest greenhouse gas inventory. EPA's Natural Gas STAR program advocates the use of a plunger lift system to reduce the need for liquids unloading, and indicates that such systems may pay for themselves in about one year. The Commission has determined that the use of technologies and practices to minimize venting, including plunger lift systems, are available and economically feasible, and encourages their use in Colorado.

Pneumatic Controllers (Section XVIII.)

The Commission recognized in a December 2008, rulemaking that pneumatic devices are a significant source of emissions. In addition, a 2013 University of Texas study concluded that methane emissions from pneumatics are higher than EPA previously estimated. Therefore, expanding the current low-bleed pneumatic device requirements statewide and further reducing emissions is appropriate and cost-effective. However, the Commission does not intend to expand the pneumatic device requirements to intermittent pneumatic controllers at this time. Further, while the use of low-bleed pneumatic controllers will result in a significant reduction of VOC and methane emissions from Colorado oil and gas facilities, no-bleed pneumatic controllers are currently commercially available to further reduce emissions from these sources.

However, because these devices can only be used at facilities with adequate electric power, and given the high cost of electrifying a facility, the Commission is only requiring the use of no-bleed pneumatic controllers at facilities that are connected to the electric grid, using electricity to power equipment, and where technically and economically feasible.

Additional Considerations

In accordance with C.R.S. §§ 25-7-105.1 and 25-7-133(3) the Commission states the rules in Sections XVII. and XVIII. of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time.

In accordance with C.R.S. § 25-7-110.5(5)(b), the Commission determines:

- (I) The revisions to Regulation Number 7 address VOC and other hydrocarbon emissions from oil and gas facilities, including storage tanks, glycol natural gas dehydrators, pneumatic controllers, well production facilities, and natural gas compressor stations. In addition to NSPS OOOO, NSPS Kb, and NSPS KKK, NESHAP HH, and NESHAP HHH may also apply to such oil and gas facilities. However, the Regulation Number 7 revisions apply on a broader basis to more storage tanks, glycol natural gas dehydrators, leaking components, and pneumatic controllers, and address more hydrocarbon emissions. For example, the Regulation Number 7 revisions address more glycol natural gas dehydrators than the major source provisions of NESHAP HH and HHH as well as more glycol natural gas dehydrators than the area source provisions of NESHAP HH, which are limited to TEG dehydrators. Similarly, the Regulation Number 7 revisions address more storage tanks than the major source provisions of NESHAP HH, as well as NSPS Kb, which exempt certain storage vessels storing condensate or petroleum prior to custody transfer. In addition, the Regulation Number 7 revisions address more component leaks than the major source provisions of NESHAP HH, as well as NSPS KKK, which has a 10,000 ppm leak threshold and only applies at natural gas processing plants.

Compared to NSPS OOOO, the revisions to Regulation Number 7 will apply a low- or no-bleed control requirement to more pneumatic controllers because NSPS OOOO only requires zero bleed pneumatic controllers at natural gas processing plants, while the Regulation Number 7 revisions no-bleed provision applies to all facilities. The revisions to Regulation Number 7 will also require a leak detection and repair program for more oil and gas operations because NSPS OOOO only requires leak detection and repair for natural gas processing plants, AVO inspections for storage vessels with controlled actual emissions greater than six (6) tpy, and annual visual inspections for leaks for subject centrifugal compressors. In contrast, the revisions to Regulation Number 7 require a leak detection and repair program for all components at all well production facilities and natural gas compressor stations. Further, the revisions to Regulation Number 7 will require storage tanks with uncontrolled actual emissions equal to or greater than 6 tpy VOC to control emissions with 95% efficiency, while NSPS OOOO's threshold is 6 tpy controlled actual emissions (i.e. 120 tpy uncontrolled actual emissions). It is the Commission's determination that, given the current and projected levels of oil and gas development in Colorado combined with the advances in technology and business practices utilized by oil and gas operators, the revisions to Regulation Number 7 are appropriate to further address hydrocarbon emissions from this sector. Such emission reductions will, among other things, protect public health and the environment, address current and future ozone concerns specific to Colorado, reduce greenhouse gas emissions, and ensure the maximum beneficial use of a valuable natural resource.

- (II) NSPS OOOO, and the other federal rules discussed in (I), are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in NSPS OOOO by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold (greater than or equal to 6 tpy controlled actual VOCs). The Commission chose to set the revised Regulation Number 7 controls at 6 tpy on an uncontrolled actual emissions basis, and therefore provide Colorado's oil and gas operators a limit for calculating the controlled potential to emit of their storage vessels, which may be used to avoid NSPS OOOO applicability.
- (III) Other federal requirements do not specifically and fully address the issues of concern to Colorado, or take into account concerns that are unique to Colorado. Specifically, during the development of NSPS OOOO, Colorado submitted comments regarding, among other things, concerns with the storage vessel definition, storage vessel control requirements, and lack of leak detection and repair requirements. Colorado's concerns were not fully addressed in NSPS OOOO, therefore, the Commission believes the revisions to Regulation Number 7 are necessary to: (a) address hydrocarbon emissions in a more comprehensive manner; (b) address oil and gas operations and equipment at lower thresholds than NSPS OOOO thresholds, yet that collectively have significant VOC and other hydrocarbon emissions in Colorado; (c) address venting of emissions from storage tanks at oil and gas facilities caused primarily by over pressurization; and (d) address leaks of fugitive hydrocarbon emissions, particularly from well production facilities and natural gas compressor stations.
- (IV) Compliance with the control requirements in the revisions to Regulation Number 7 provide Colorado's oil and gas operators a limit for calculating the controlled potential to emit of their storage vessels, thereby allowing many of these sources to avoid regulation under NSPS OOOO. Additionally, the revisions may prevent or reduce the need for costlier retrofits at a later date. Colorado may be required to comply with a lower ozone NAAQS in the near future and the Denver Metro/North Front Range area is currently in nonattainment with the ozone NAAQS, while other areas in the State are seeing elevated ozone levels, including areas of increasing oil and gas development. The revised rules are proactive and intended to reduce ozone levels now by utilizing controls and techniques already being used by some Colorado oil and gas operators, or that are readily available.
- (V) Adoption of these revisions at this time allows many of Colorado's oil and gas operators to utilize the controls established in the revisions to Regulation Number 7 to avoid NSPS OOOO storage vessel requirements. Postponement of adoption would potentially subject these sources to compliance with NSPS OOOO and then compliance with State requirements once State controls become effective.
- (VI) The revisions to Regulation Number 7 do not place limits on the growth of Colorado's oil and gas industry. Instead, the rules address hydrocarbon emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry. Indeed, the oil and gas industry has already grown in Colorado while utilizing many of the technologies and practices set forth in these revisions.

- (VII) The revisions to Regulation Number 7 establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources. Rules of general applicability have been developed along with tiered requirements and exclusions that tailor the rules to the regulated sources within the oil and gas sector. Furthermore, the application of the Regulation Number 7 revisions to oil and gas owners and operators regardless of location in the ozone nonattainment or attainment areas is equitable because the nonattainment area is not the only area in Colorado with ozone issues. For example, the Rangely monitor in western Colorado shows violations of the 2008 ozone standard and existing modeling shows that either the nonattainment area has increased its contribution to background ozone or ozone concentrations in the attainment area flowing into the nonattainment area have increased. Notably, the Division's inventory shows that the oil and gas industry contributes more than 50% of the VOC emissions outside the nonattainment area. This monitoring, modeling, and inventory data, considered with the likelihood of a lower ozone NAAQS and the expected growth of the oil and gas sector state-wide, supports the application of the Regulation Number 7 revisions to oil and gas sources in both the nonattainment and attainment areas.
- (VIII) The oil and gas industry is a large anthropogenic stationary source of VOCs, a precursor pollutant to ozone. If the revisions to Regulation Number 7 are not adopted, other aspects of oil and gas operations or other sectors may be looked to for additional emission reductions. In reductions must come from other operations or sectors at this time, the cost effectiveness would decrease because these revisions reduce emissions from the most significant contributors to VOC emissions and costs will be higher for less emissions reductions from less significant contributors.
- (IX) The majority of sources subject to the revised rules in Regulation Number 7 will not be subject to federal procedural, reporting, or monitoring requirements. Those few sources subject to both NSPS OOOO (e.g. storage vessels emitting 120 tpy uncontrolled actual VOC emissions) or NESHAP HH and HHH (e.g. glycol natural gas dehydrators at major sources of HAPs and TEG glycol natural gas dehydrators at area sources of HAPs) and Regulation Number 7 will be required to comply with both regulations. The procedural, reporting, and monitoring requirements of Regulation Number 7, to the extent different than federal requirements, are necessary to ensure compliance with and document the effectiveness of the revisions.
- (X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable in the 8-Hour Ozone Nonattainment Area state-wide, such as the requirements for auto-igniters and pneumatic controllers. In addition, oil and gas owners and operators are already using many of the control devices and techniques intended to be used to comply with these revisions. The lead-in time provides owners and operators time to install control devices and develop plans for compliance. Should unanticipated events occur, such as a lack of availability of control devices, the revisions provide for Division approved extensions to compliance.
- (XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will contribute to the prevention of hydrocarbon emissions in a cost-effective manner. Significantly, the Commission expressly finds that the cost-effectiveness of the VOC emission reductions alone supports the revisions to Regulation Number 7. The reductions of other hydrocarbon emissions, such as methane, add to the already cost-effective and appropriate emission reduction requirements.
- (XII) Alternative rules, such as the alternative proposals provided by several parties during the rulemaking process, requiring differing or additional controls for oil and gas facilities could

also provide reductions in hydrocarbon emissions. The Commission could have adopted some or all of the proposed revisions or proposed alternatives. However, the proposed revisions to Regulation Number 7 were developed during a lengthy stakeholder process and provided a balanced approach, reducing emissions from the oil and gas industry while allowing the sector to continue to play a critical role in Colorado's economy and the nation's energy independence. The alternative proposals provided during the rulemaking process were primarily either more or less stringent versions of the proposed revisions, further illustrating the balanced approach of the proposed revisions. Furthermore, a no action alternative would very likely only delay future reductions in hydrocarbon emissions, including ozone precursor pollutants, necessary for reducing ozone in Colorado.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

The incorporation by reference of NSPS OOOO in Regulation Number 6 does not affect the requirements of these revisions to Regulation Number 7. Instead, these revisions to Regulation Number 7 are designed and intended to address differences and overlaps between NSPS OOOO and current state requirements, and to include additional emission control measures for oil and gas production and equipment. To the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

- (I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.
- (II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of hydrocarbon emissions.
- (III) Evidence in the record supports the finding that the rules shall being about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.
- (VI) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.
- (V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

O. November 17, 2016 (Sections I., X., XII., XIII., XVI., XIX.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

On May 21, 2012, the Denver Metro/North Front Range (“DMNFR”) area was designated as Marginal nonattainment for the 2008 8-hour Ozone National Ambient Air Quality Standard (“NAAQS”), effective July 20, 2012 (77 Fed. Reg. 30088). On May 4, 2016, the U.S. Environmental Protection Agency’s (“EPA”) published a final rule that determined that DMNFR area failed to attain the 2008 8-hour Ozone NAAQS by the applicable Marginal attainment deadline and therefore reclassified the DMNFR area to Moderate and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone season data. Due to the reclassification, additional planning requirements were triggered, including the requirement to submit revisions to the State Implementation Plan (“SIP”) that address the Clean Air Act’s (“CAA”) Moderate nonattainment area requirements, as set forth in CAA Section 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (See 80 Fed. Reg. 12264 (March 6, 2015)).

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., (“Act”), Section 25-7-105(1)(a) directs the Commission to promulgate such rules and regulations necessary for the proper implementation and administration of a comprehensive state implementation plan that will assure attainment and maintenance of national ambient air quality standards. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106(1)(c) and (2) also authorize the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution, and monitoring and recordkeeping requirements. Section 25-7-109(1)(a) authorizes the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources of air pollutants.

Purpose

The Regional Air Quality Council (“RAQC”) and the Colorado Department of Public Health and Environment, Air Pollution Control Division (“Division”) conducted a public process to develop the associated SIP and supporting rule revisions. Separately, EPA had expressed concerns with approving previous Regulation Number 7 revisions related to oil and gas control requirements and submitted in 2009 and 2013 for inclusion in Colorado’s ozone SIP.

In response to these related but separate issues, the Commission revised Regulation Number 7 to strengthen Colorado’s ozone SIP; and include reasonably available control technology (“RACT”) requirements for lithographic and letterpress printing, industrial cleaning solvents, and major sources of volatile organic compounds (“VOC”) or nitrogen oxides (“NOx”). More specifically, the Commission revised the applicability of Regulation Number 7 in Section I.A.1.; included the existing combustion device auto-igniter requirements in Section XII.C.1.e. and XII.E.2. in Colorado’s ozone SIP; included existing audio, visual, olfactory (“AVO”) storage tank inspection requirements for condensate storage tanks in Colorado’s ozone SIP in Section XII.E.4.e.; added requirements for lithographic and letterpress printing in Section XIII.B.; added requirements for industrial cleaning solvents in Section X.E.; and added requirements for major sources in Sections XVI. and XIX.

Apart from the Moderate nonattainment area ozone SIP, the Commission revised Regulation Number 7 to address EPA’s monitoring, recordkeeping, reporting, and other concerns with previously submitted Regulation Number 7 revisions. The Commission updated federal rule references for natural gas processing plants in Section XII.G.1.; renumbered the current Sections XII.G.5. and XII.G.6. under Section XII.I.; added monitoring, recordkeeping, and reporting requirements for glycol natural gas dehydrators in Sections XII.H.5. and XII.H.6.; and addressed other EPA concerns in Sections XII.C.1.c., XII.C.1.d., XII.C.2.a.(ii)(B), XII.E.3., and XII.H.4.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Ozone reclassification SIP revisions

8-hour ozone control area

All provisions of Regulation Number 7 currently apply to the Denver 1-hour ozone nonattainment and attainment/maintenance area. The 1-hour ozone area does not include all of Adams and Arapahoe counties or the portions of Larimer and Weld counties included in the 8-hour ozone control hour. Therefore, to ensure that all sources in the 8-hour ozone nonattainment area are subject to applicable RACT requirements in Regulation Number 7 on a federally enforceable basis, the Commission revised Regulation Number 7, Section I.A.1.a. to state that all provisions apply to both the 1-hour and 8-hour ozone areas. The Commission intends that provisions clearly marked "state-only" continue to be enforceable only on a state-only basis, and are not included in the SIP.

Auto-igniter and storage tank AVO

Regulation Number 7, Section XII.C.1.e. includes auto-igniter requirements for combustion devices used to control emissions of VOCs. Pursuant to Section XII.E., the auto-igniter must be inspected weekly to ensure it is properly functioning. Prior to the revision, these requirements were "state-only". The Commission revised these provisions to include the auto-igniter installation, operation, and monitoring requirements in the SIP.

Regulation Number 7, Section XII.E. includes requirements for owners or operators of condensate storage tanks subject to Section XII.D. to inspect combustion devices, vapor recovery units, control devices, and thief hatches. These are SIP requirements. Regulation Number 7, Section XVII.C.1.d. also requires of owners or operators of storage tanks subject to Section XVII. to conduct AVO and additional visual inspection at the same frequency as liquids load-out. The requirements of Section XVI.C.1.d. are enforceable on a "state-only" basis. The Commission revised Section XII. to include in the SIP, the requirement that owners and operators conduct AVO inspections of condensate storage tanks with uncontrolled actual VOC emissions of 6 tons per year ("tpy") or greater, making them federally enforceable.

Lithographic and letterpress printing RACT

Pursuant to CAA Section 182(b), Colorado's ozone SIP must provide for implementation of RACT at sources of VOC for which EPA has issued a Control Technique Guideline ("CTG"). EPA's Offset Lithographic Printing and Letterpress Printing CTG ("Printing CTG") addresses VOC emissions from the use of fountain solutions, cleaning materials, and inks at lithographic and letterpress printing operations. The Printing CTG recommends controlling VOC emissions from heatset printing with dryer emissions of at least 25 tpy of VOC from heatset inks with add-on control technology. The Printing CTG recommends controlling VOC emissions from cleaning materials and fountain solutions at printing operations with facility emissions equal to or greater than 15 lb/day by limiting the VOC content of cleaning materials and fountain solutions. The Printing CTG also recommends work practices for printing operations with facility emissions equal to or greater than 15 lb/day.

Colorado has sources in the ozone nonattainment area in this CTG VOC source category not currently subject to regulatory RACT requirements. Therefore, the Commission included these requirements in Section XIII.B. as RACT for these sources. However, rather than an applicability threshold of 15 lbs/day, the Commission adopted an applicability threshold of 3 tpy. This is roughly equivalent to the 15lbs/day threshold recommended in the Printing CTG. Based on the Printing CTG, the Commission added language to Section XIII.B.1.b. clarifying that fountain solutions, cleaning materials, inks (which include varnishes) and coatings used in lithographic and letterpress printing presses are considered part of the printing process and are not subject to the surface coating or industrial cleaning solvent requirements in Regulation Number 7. With respect to the compliance threshold for Section XIII.B., if the preceding 2 calendar year average indicates that a source meets or exceeds the 3 tpy threshold, then the source must comply with Section X.E. for the current calendar year. Only emissions from the printing operation and cleaning thereof should be considered in determining if emissions exceed 3 tpy.

The Commission included additional work practices, a VOC content limit for inks and monitoring, recordkeeping and performance testing requirements that are not specified in the Printing CTG but are intended to correspond to current permit requirements and ensure the enforceability of the requirements. With respect to the work practice requirements contained in Section XIII.B.1.c., the Commission applied these requirements to all lithographic and letterpress printing operations, regardless of potential or actual VOC emissions, because they are minimally burdensome, good housekeeping requirements that reduce emissions and correspond to current permit requirements. With respect to the VOC content limit for inks, the Commission included a 40% limit for heatset web offset and heatset web letterpress printing operations that require higher VOC content ink, and a 30% limit for all other lithographic and letterpress printing operations that are commonly already using low VOC inks. Compliance with the VOC content requirement for inks is demonstrated using a weighted average which takes into account the amount of the different inks used and their respective VOC contents.

For consistency with the Printing CTG, cleaning solutions are subject to VOC content or vapor pressure requirements, except that sources using less than 110 gallons of non-compliant cleaning materials per calendar year are exempt from the VOC content or vapor pressure requirements. Larger heatset printing operations, whose maximum allowable emissions before controls from petroleum inks are 25 tpy VOC or more, are subject to a control requirement (not capture and control). Printing operations' emissions are more difficult to capture, and so capture is not considered in the percent control requirements. However, good air pollution control practices apply at all times.

Industrial cleaning solvents RACT

EPA's CTG for Industrial Cleaning Solvent ("Cleaning Solvent CTG") addresses solvent use in cleaning operations such as spray gun cleaning, spray booth cleaning, large manufactured components cleaning, parts cleaning, equipment cleaning, line cleaning, floor cleaning, tank cleaning, and small manufactured components cleaning. The Cleaning Solvent CTG applies to facilities with VOC emissions from the use of industrial cleaning solvents equal to or greater than 15 lb/day of VOC. The Cleaning Solvent CTG recommends a cleaning solvent VOC content limit and work practices.

Colorado has sources in the ozone nonattainment area in this Cleaning Solvent CTG VOC source category not currently subject to regulatory RACT requirements. Therefore, the Commission included requirements in Section X.E. as RACT. However, rather than an applicability threshold of 15 lbs/day, the Commission adopted an applicability threshold of 3 tpy on a calendar basis. This is roughly equivalent to the 15lbs/day threshold recommended in the CTG. The Commission intended for the term "industrial cleaning solvent operation" to be broad and apply to a wide range of work areas where manufacturing or repair activities are performed, but not to residential or janitorial cleaning.

The Commission included language to clarify that VOC emissions that are exempt from the industrial cleaning solvent rule do not count toward this 3 tpy threshold. Therefore, when determining whether a facility meets the applicability threshold of 3 tpy, a source should include facility-wide emissions from all industrial cleaning solvent operations and subtract those emissions that are exempt under Section X.E.4. In adopting the VOC content limit in Section X.E.1.a. and the vapor pressure limit in Section X.E.1.b., the Commission intended for these to be straight, as-applied limits for all industrial cleaning solvents used and not a weighted average. Additionally, in adopting the 90% control efficiency compliance option in Section X.E.1.c., the Commission did not intend for this control efficiency to include capture efficiency. The Commission acknowledged that capture efficiency may be lower than the control efficiency because industrial cleaning solvents are often used over large industrial complexes and result in relatively small VOC emissions.

With respect to the compliance threshold for Section X., if the preceding 2 calendar year average indicates that a source meets or exceeds the 3 tpy threshold, then the source must comply with Section X.E. for the current calendar year. The Commission also included monitoring, recordkeeping and reporting requirements that are not specified in the Cleaning Solvent CTG but are intended to align with current permit recordkeeping requirements and ensure the enforceability of the requirements.

The Commission included language in Section X.E.4.a.(ii) providing that industrial cleaning solvent operations subject to a work practice or emission control requirement in another federally enforceable section of Regulation Number 7 that establishes RACT are exempt from the requirements of Section X. This provision was included so as not to subject sources to overlapping, duplicative, or contradictory RACT requirements. Therefore, if an industrial cleaning solvent operation is subject to a work practice or emission control requirement contained in another, federally approved section of Regulation Number 7, including but not limited to Sections IX. (surface coating operations), X.B. through X.D. (solvent cold-cleaners, non-conveyorized degreasers, and conveyorized degreasers), and XIII. (graphic arts and printing), then that operation would not also be subject to the requirements of Section X.E.4. However, this provision is not intended to exempt an industrial cleaning solvent operation from Section X. when the operation is subject to the restriction on disposal of VOCs by evaporation or spillage contained in to Section V.A. (and RACT is determined to be nothing). Therefore, if an industrial cleaning solvent operation is subject to Section V.A. and RACT is determined to be nothing, the operator must comply with Section X. Conversely, if an industrial cleaning solvent operation is subject to Section V.A. and RACT is determined to be a work practice or emission control requirement, then the operation is exempt from Section X. Lastly, the Commission adopted additional exemptions recommended in the Cleaning Solvent CTG in Section X.E.4.b. as well as an alternative compliance option for area source aerospace facilities in Section X.E.4.c. due to the unique solvent cleaning needs of those source categories.

Control requirements do not account for capture and control. General industrial solvent use emissions are more difficult to capture, and so capture is not considered in the percent control requirements. However, good air pollution control practices apply at all times.

Major VOC and NOx source RACT

Colorado has major sources of VOC or NOx (sources that emit or have the potential to emit greater than 100 tpy) in the DMNFR. While many of these sources are currently subject to regulatory RACT requirements in Colorado's SIP, some of the sources or emissions points are subject to RACT requirements in federally enforceable permits or New Source Performance Standard ("NSPS") or National Emission Standard for Hazardous Air Pollutants ("NESHAP"). However, as a Moderate nonattainment area, Colorado is submitting a SIP revision to include provisions requiring the implementation of RACT for major sources of NOx or VOC in the DMNFR. Therefore, the Commission included a work practice for combustion equipment at major sources of NOx emissions in Section XVI., a requirement for specific major sources to provide RACT analyses to the Division in Section XIX.B., and incorporated by reference applicable requirements of a NSPS or NESHAP in Sections XIX.C-G.

Specifically, the Commission adopted a combustion process adjustment requirement for individual pieces of combustion equipment at major sources of NO_x in Section XVI.D., expanding on work practices currently required in federal NESHAP. The combustion process adjustment was modeled after NESHAP DDDDD, which applies to boilers and process heaters at major HAP sources, and NESHAP ZZZZ, which establishes various requirements for stationary reciprocating internal combustion engines. Section XVI.D. is intended to apply to some equipment that is not subject to work practices under the NESHAPs (e.g., natural gas fired boilers at area sources of HAPs) that have uncontrolled actual NO_x emissions (annual emission rate corresponding to the annual process rate listed on the Air Pollutant Emission Notice without consideration of any emission control equipment or procedures) equal to or greater than 5 tpy. The Commission intended major NO_x sources to use the most recent APEN submitted to the Division as of January 1, 2017, to determine whether the combustion equipment is subject to the requirement to conduct an initial combustion process adjustment by April 1, 2017, or alternatively document reliance on an allowed, alternative adjustment. Subsequent determinations will be based on the most recent APEN submitted to the Division as of the year the combustion equipment may be subject to the combustion process adjustment requirements (e.g., most recent APEN submitted to the Division as of January 1, 2018, to determine whether a combustion process adjustment is required in 2018). In addition to the specific adjustment requirements, the Commission intended owners and operators to operate and maintain subject equipment consistent with manufacturer specifications or best combustion engineering practices.

The Commission also established RACT requirements for emission points at major sources of VOC or NO_x in the DMNFR area in Section XIX. In Section XIX.A., the Commission listed all major sources of VOC or NO_x at the time of adoption of the Moderate nonattainment area RACT SIP. The Commission determined that not all emission points above permitting thresholds at major sources were necessarily subject to existing regulatory RACT requirements in Regulation Number 7 or federally enforceable emission limits in Colorado's Regional Haze SIP. Therefore, in Sections XIX.C. through XIX.G., the Commission incorporated federal NSPS or NESHAP requirements, including monitoring, recordkeeping, and reporting requirements, for some sources to further satisfy Colorado's RACT obligation for Colorado's major VOC and NO_x sources. The Commission acknowledges concerns over potential EPA revisions to NSPS and NESHAP incorporated by reference in Sections XIX.C. through XIX.G., and intended that sources comply with applicable requirements in the most up-to-date version of the federal rule, or alternative requirements approved by EPA in accordance with the NSPS or NESHAP. The Commission also directs the Division to initiate efforts to update the incorporation by reference in the SIP, as necessary and with all due diligence. Sources identified in Section XIX.A. but not specifically included in Sections XIX.B. through XIX.G., were determined to be subject to other, existing regulatory RACT requirements in Colorado's SIP (see the Moderate ozone SIP revision, RACT Chapter 6 and the Technical Support Document for Reasonably Available Control Technology for Major Sources for additional detail). Concerning major sources or source emission points not subject to other, existing regulatory RACT requirements in Colorado's SIP or specified in Sections XIX.C. through XIX.G., the Commission required owners or operators to submit RACT analyses for the facility or specific emission points to the Division by December 31, 2017. The RACT analyses should identify potential options to reduce NO_x and/or VOC emissions from the facility or emission point(s), propose RACT for that facility or point, propose associated monitoring, propose a schedule for implementation, and include economic and technical information showing why the RACT proposal is RACT for the particular facility or point. These RACT analyses are not to be limited by a January 1, 2017, implementation date.

CoorsTek submitted a permit application to limit permitted emissions of VOC below 100 tpy. Metro Wastewater Reclamation District submitted an application for minor modification to its Title V permit to correct inconsistencies and remove obsolete limits, which lowered the combined Metro Wastewater/Suez Denver Metro permitted NO_x emission limit below 100 tpy. Consequently, the Commission determined that the facilities no longer met the definition of a major source, and therefore were not included in Section XIX. Should either source fail to obtain such federally enforceable permits by July 1, 2018, the Commission directs the Division, with all due diligence, to initiate efforts to establish RACT requirements for that source in Colorado's ozone SIP.

Current SIP review

In 2009, the Commission submitted revisions to Regulation Number 7, Section XII. to EPA related to the 1997 ozone NAAQS attainment plan. In 2011, EPA approved the attainment demonstration but disapproved portions of the Regulation Number 7 revisions. In 2013, the Commission submitted revisions to Regulation 7, Section XII. to EPA to address EPA's disapproval. During the review of the 2013 submittal, EPA noted additional concerns with the monitoring, recordkeeping, and reporting requirements for natural gas processing plants and glycol natural gas dehydrators, as well as other concerns unrelated to the attainment demonstration for the SIP revision required following the reclassification of the DMNFR area to Moderate.

Natural gas processing plants

Regulation Number 7, Section XII.G.1. identifies a leak detection and repair ("LDAR") program applicable to natural gas processing plants. This "LDAR program" includes all applicable requirements in NSPS KKK. EPA has promulgated new LDAR programs for natural gas processing plants in NSPS OOOO and NSPS OOOOa. Therefore, the Commission updated references to applicable federal NSPS (i.e., NSPS OOOO and NSPS OOOOa) monitoring, recordkeeping, and reporting requirements for natural gas processing plants in the SIP.

Glycol natural gas dehydrators

Regulation Number 7, Section XII.H. already includes a 90% control requirement for glycol natural gas dehydrators. This is a SIP requirement. During the review of the 2013 submittal, EPA noted practical enforceability concerns with the monitoring, recordkeeping, and reporting requirements for glycol natural gas dehydrators. Therefore, the Commission added monitoring, recordkeeping, and reporting requirements for glycol natural gas dehydrators in the SIP to address EPA's concerns with ensuring compliance with the control requirement. The Commission based these requirements off of the Division's glycol natural gas dehydrator Operation and Maintenance Plan template to align the Section XII.H. monitoring, recordkeeping, and reporting requirements with the Operation and Maintenance Plan template, where possible. For any glycol dehydration system monitoring, recordkeeping and reporting requirement adopted for inclusion in the SIP during this hearing that conflicts with a similar provision in a Division approved Operation and Maintenance Plan, the Commission intends that sources only have to comply with the provision adopted for inclusion in the SIP and not the competing requirement in the approved Operation and Maintenance Plan. Further, the Commission directs the Division to work with industry to revise the Division's glycol dehydration systems Operating and Maintenance Plan template to remove requirements that are duplicative of the Section XII.H. monitoring, recordkeeping, and reporting requirements, to alleviate competing requirements with Section XII.H., as necessary.

EPA requested revisions

EPA also noted concerns with other previously submitted provisions in Section XII. EPA requested minor changes to Section XII.C.1.c., and a reversion to previously approved SIP language in Sections XII.C.1.d. and XIII.E.3.a. to address concerns with discretionary language. In response, the Commission revised Section XII.C.1.c. and reverted to previously approved SIP language in Sections XII.C.1.d. and XII.E.3.a., as requested by EPA.

Incorporation by Reference in Section XIX

Section 24-4-103(12.5) of the Colorado Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information, making the regulations available and because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. However, these regulations are included in the SIP in order to establish RACT, which must be included in the SIP to satisfy CAA Sections 172(c) and 182(b). Therefore, in order to comply with Part D of the CAA, the Commission has incorporated federal regulations in Section XIX.C through H by reference.

Additional Considerations

Colorado must revise Colorado's ozone SIP to address the ozone Moderate nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's Moderate nonattainment area obligations, including those related to RACT. The Commission also adopted revisions to Regulation Number 7 to address EPA concerns that are unrelated to the reclassification to Moderate. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs; however, in accordance with C.R.S. § 25-7-110.5(5)(b), the Commission nonetheless determines:

- (I) The revisions to Regulation Number 7 address combustion device auto-igniters, condensate storage tank inspections, and glycol natural gas dehydrators at oil and gas facilities and equipment leaks at natural gas processing plants. NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, and NESHAP HHH may also apply to such oil and gas facilities. However, the Regulation Number 7 revisions apply on a broader basis to more storage tanks and glycol natural gas dehydrators. For example, Regulation Number 7 addresses more glycol natural gas dehydrators than the major source provisions of NESHAP HH and HHH as well as more glycol natural gas dehydrators than the area source provisions of NESHAP HH, which are limited to tri ethylene glycol ("TEG") dehydrators. The Commission revised Regulation Number 7 to include glycol natural gas dehydrator monitoring, recordkeeping, and reporting requirements to ensure compliance with the current 90% system-wide control requirement in Section XII.D. Similarly, Regulation Number 7 addresses more storage tanks than the major source provisions of NESHAP HH, as well as NSPS Kb, which exempt certain storage vessels storing condensate or petroleum prior to custody transfer. Regulation Number 7 also addresses a broader set of storage tanks than NSPS OOOO and NSPS OOOOa, which address only those storage tanks with emissions greater than 6 tpy controlled actual emissions (i.e., 120 tpy uncontrolled actual emissions) and do not require auto-igniters on combustion devices. The Commission revised Regulation Number 7 to include the auto-igniter and condensate storage tank AVO inspections in Colorado's SIP to strengthen Colorado's SIP and support Colorado's 2017 emissions inventory. In addition, Regulation Number 7 addresses more equipment leaks at natural gas processing plants than NSPS KKK, which only applies to natural gas processing plants constructed, reconstructed, or modified after January 20, 1984. The Commission revised Regulation Number 7 to reference the more recent equipment leak detection and repair requirements in NSPS OOOO and NSPS OOOOa.

The revisions to Regulation Number 7 also address RACT requirements for lithographic and letterpress printing, industrial cleaning solvents, and major sources of VOC and NOx in Colorado's ozone nonattainment area. EPA published CTGs for lithographic and letterpress printing and industrial cleaning solvents in 2006. The Commission revised Regulation Number 7 to include regulatory RACT requirements for these VOC source categories. Colorado's major sources of VOC and NOx are subject to various and numerous NSPS or NESHAP, Regulation Number 7 RACT requirements, or RACT/beyond RACT analyses. The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and NOx in the SIP. Specifically, the Commission revised Regulation Number 7, Sections XVI. and XIX. to include source specific regulatory RACT requirements and a combustion process adjustment for combustion equipment at major sources of NOx. MACT DDDDD, MACT JJJJJ, MACT ZZZZ, MACT YYYY, NSPS GG, NSPS KKKK, NSPS IIII, and NSPS JJJJ may apply to such combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to more combustion equipment.

- (II) The federal rules discussed in (I), are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold.
- (III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here.
- (IV) Colorado will be required to comply with a lower ozone NAAQS in the near future. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.
- (V) EPA has established a January 1, 2017, deadline for this SIP submission. There is no timing issue that might justify changing the time frame for implementation of federal requirements.
- (VI) The revisions to Regulation Number 7 Section XII. strengthen Colorado's SIP, which currently addresses emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry. The revisions to Regulation Number 7 Sections X. and XIII. recognize products and practices currently utilized by printing and industrial cleaning solvent operations. The revisions to Regulation Number 7 Sections XVI. and XIX. are also specific to existing emission points at major sources of VOC and NOx, allowing for continued growth at Colorado's major sources.

- (VII) The revisions to Regulation Number 7 Section XII. establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources. The revisions to Regulation Number 7 Sections X., XIII., and XVI. similarly establish the categorical RACT requirements for similarly situated and sized sources. Where a source is not subject to a categorical RACT requirement, RACT is, by its nature, determined on a case-by-case basis.
- (VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018, EPA will likely reclassify Colorado as a serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs.
- (IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.
- (X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for auto-igniters, condensate storage tank inspections, and equipment leaks at natural gas processing plants. Other revisions reflect changes in industry practice and market forces, such as the VOC content of printing materials and cleaning solvents. Similarly, the revisions concerning major sources of VOC and NOx generally reflect current emission controls and work practices.
- (XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.
- (XII) Alternative rules could also provide reductions in ozone and help to attain the NAAQS. The Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an unapprovable SIP.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the Moderate Nonattainment area requirements. However, to the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

- (I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.
- (II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of the ozone precursors VOC and NOx.
- (III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.

- (IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.
- (V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

P. November 16, 2017 Revisions to Section II., XII., Section XVII., and Section XVIII.

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedure Act Sections 24-4-103, C.R.S. and the Colorado Air Pollution Prevention and Control Act Sections 25-7-110 and 25-7-110.5, C.R.S. ("the Act").

Basis

On May 4, 2016, the U.S. Environmental Protection Agency's ("EPA") published a final rule that determined that Colorado's Marginal ozone nonattainment area failed to attain the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"). EPA, therefore, reclassified the Denver Metro North Front Range ("DMNFR") area to Moderate and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone data.

As a result of the reclassification, on May 31, 2017, Colorado submitted to EPA revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") Moderate nonattainment area requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (See 80 Fed. Reg. 12264 (March 6, 2015)). As a Moderate nonattainment area, Colorado must revise its SIP to include Reasonably Available Control Technology ("RACT") requirements for each category of volatile organic compound ("VOC") sources covered by a Control Technique Guideline ("CTG") for which Colorado has sources in the DMNFR that EPA finalized prior to a nonattainment area's attainment date. EPA finalized the Control Techniques Guidelines for the Oil and Natural Gas Industry ("Oil and Gas CTG") on October 27, 2016, with a state SIP submittal deadline of October 27, 2018. Given this timing, the November 2016, SIP revisions did not include RACT for the oil and natural gas source category and Colorado must further revise its SIP.

The Oil and Gas CTG recommends controls that are presumptively approvable as RACT and provide guidance to states in developing RACT for their specific sources. In many cases, Colorado has similar, or more stringent, regulations comparable to the recommendations in the Oil and Gas CTG, though many of these provisions are not currently in Colorado's Ozone SIP. Therefore, the Commission is adopting RACT for the oil and gas sources covered by the Oil and Gas CTG (CTG as of October 27, 2016) into the Ozone SIP (Sections XII. and XVIII.). In order to make additional progress towards attainment of the NAAQS, the Commission is also adopting State Only revisions to require owners or operators of natural gas-driven pneumatic controllers in the DMNFR area to inspect and maintain pneumatic controllers.

Further, the Commission is making clarifying revisions and typographical, grammatical, and formatting corrections throughout Regulation Number 7.

Specific Statutory Authority

Section 25-7-105(1) of the Act directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in Section 25-7-102 and are necessary for the proper implementation and administration of the Act. The Act broadly defines air pollutant and provides the Commission broad authority to regulate air pollutants. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program.

Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Sections 25-7-109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides the Commission broad authority to regulate hydrocarbons.

Purpose

As discussed above, Colorado must adopt RACT into its Ozone SIP for sources covered by the Oil and Gas CTG. While the Oil and Gas CTG recommends presumptive RACT, it does allow states the flexibility to determine what constitutes RACT for the state's covered sources. Further, while EPA's Oil and Gas CTG implementation memorandum provides guidance that the emission controls determined by the state to be RACT for the sources covered by the Oil and Gas CTG must be implemented as soon as practicable but in no case later than January 1, 2021, states also have the flexibility to determine the appropriate implementation timeframe for the sources within the state's ozone nonattainment area. The Commission determined that some of Colorado's existing regulations (*i.e.*, the "system-wide" control program for condensate tanks in Section XII.D.2.) achieve greater emission reductions than the RACT recommended by the Oil and Gas CTG. The Commission determined that some sources covered by the Oil and Gas CTG were not addressed in existing regulations (*i.e.*, pneumatic pumps).

The Commission also determined that some sources addressed in the Oil and Gas CTG (*i.e.*, components at well production facilities and natural gas compressor stations, compressors, pneumatic controllers) are already subject to existing regulations that were not yet part of Colorado's Ozone SIP. The Commission adopted many of these rules in 2014, and intends to preserve the substance of these rules, where possible, in moving them into the Ozone SIP, while making a few adjustments and improvements in response to recommendations in the Oil and Gas CTG. The Commission also adopted correlating revisions to the applicability provisions of Sections II. and XII.

The Commission relied on existing regulations in the Ozone SIP for RACT for condensate storage tank controls to satisfy Colorado's obligation to address storage vessels under the Oil and Gas CTG. The Commission adopted requirements for pneumatic pumps in Section XII. to address recommendations in the Oil and Gas CTG. The Commission revised the existing SIP requirements in Section XII.G. for equipment leaks at natural gas processing plants to address recommendations in the Oil and Gas CTG. The Commission duplicated into the Ozone SIP from Section XVII. provisions for compressors and leak detection and repair ("LDAR") for components at well production facilities and natural gas compressor stations. The Commission adjusted these LDAR requirements to address recommendations in the Oil and Gas CTG, along with updates to the recordkeeping and reporting requirements. Corresponding revisions to the LDAR program in Section XVII. are made on a State Only basis. The Commission also revised Section XVIII. to include existing State Only requirements for continuous bleed, natural gas-driven pneumatic controllers in the Ozone SIP and specify that continuous bleed, natural gas-driven pneumatic controllers located at natural gas processing plants maintain a natural gas bleed rate of zero scfh.

The Commission adopted State Only provisions for the inspection and maintenance of natural gas-driven pneumatic controllers in Section XVIII.

The Commission also made clarifying revisions and corrected typographical, grammatical, and formatting errors found within the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Oil and Gas CTG, generally

The Oil and Gas CTG provides recommendations for states to consider in determining RACT for certain oil and natural gas industry emission sources. EPA included storage vessels, pneumatic controllers, pneumatic pumps, compressors, equipment leaks, and fugitive emissions in the Oil and Gas CTG because EPA determined that these sources are significant sources of VOC emissions. EPA defines RACT as “the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.” States may implement approaches that differ from the recommendations in the Oil and Gas CTG so long as they are consistent with the CAA, EPA’s implementing regulations, and policies on interpreting RACT.

Applicability to hydrocarbons (Section II.B.)

Section II.B. currently exempts negligibly reactive volatile organic compounds, such as methane and ethane, from requirements of the SIP, while making hydrocarbon emissions, including methane and ethane, subject to State Only regulation under Sections XVII. and XVIII. Section XVII. sets a threshold for leaks requiring repair that is based on the concentration of hydrocarbons, as determined using EPA Method 21. Section XII.L. applies the same EPA Method 21 hydrocarbon threshold for leaks requiring repair. The Commission revised Section II.B. to clarify that the Section XII.L. hydrocarbon threshold and Section XVIII. natural gas emission standards serve only as VOC indicators and the SIP does not regulate hydrocarbon emissions.

The continuous bleed, natural gas-driven pneumatic controller requirements in Section XVIII. reduce natural gas emissions, which consists of other pollutants in addition to VOCs. Despite the presence of other constituents, natural gas is principally methane and the Commission intends to regulate emissions of natural gas as hydrocarbons, including methane and ethane, on a State Only basis as described in Sections II.B. and XVIII. The Oil and Gas CTG also utilizes a natural gas bleed rate standard for continuous bleed pneumatic controllers and the Oil and Gas CTG LDAR program employs a methane-based threshold for EPA Method 21 leak detection. Therefore, these revisions are consistent with the Oil and Gas CTG and the CAA.

While the revisions to Sections XII. and XVIII. to include provisions in Colorado’s Ozone SIP are limited to the DMNFR, the Commission acknowledges the importance of reducing hydrocarbon emissions from the oil and gas sector (*i.e.*, upstream, midstream, and transmission) statewide. Therefore, without prescribing any particular outcome, the Commission directs the Division to initiate and lead a stakeholder process over the 2018-2019 timeframe to evaluate potential areas for cost-effective hydrocarbon emission reductions. Stakeholders will nominate topics for evaluation, which may include, but are not limited to, the frequency of LDAR inspections, transmission segment compressor emissions, natural gas-driven and zero emission pneumatic controllers outside the DMNFR (to be informed by the pneumatic study and inspection program), and potential expansion of the requirements adopted in the DMNFR as part of this rulemaking. The Division will brief the Commission on the stakeholder process in January 2019 and present recommendations for any new proposals for emission reductions by no later than January 2020. The Commission intends that one representative of industry, local government, and the environmental community each will have the opportunity to speak during the briefings.

Applicability of Section XII. (Section XII.A.)

The Commission is clarifying the applicability of Section XII. Historically, Section XII. has applied to operations that involve the collection, storage, or handling of condensate in the DMNFR. While this remains the case, the requirements in Section XII.J. for compressors, Section XII.K. for pneumatic pumps, and Section XII.L. for components at well production facilities and natural gas compressor stations also apply to those facilities and equipment collecting, storing, or handling other hydrocarbon liquids.

Section XII.A.5. further provides that subject well production facilities are those with uncontrolled actual VOC emissions greater than or equal to one ton per year (“tpy”). This applicability threshold addresses the Oil and Gas CTG’s recommended barrels of oil equivalent (“BOE”) exemption. EPA crafted the BOE exemption believing that well production facilities with an average production less than 15 BOE per well per day were inherently low emitting facilities. EPA later determined that information submitted on the draft CTG and proposed NSPS OOOOa did not support this conclusion. Therefore, in addition to the complications concerning tracking BOE, the Commission chose to rely upon an uncontrolled actual VOC tpy threshold for well production facility applicability. The use of a tpy threshold is also consistent with Colorado’s current air pollutant reporting and permitting thresholds.

Further, Section XII.A. historically exempted from the requirements of Section XII. those operations reflecting a total of less than 30 tons-per-year of actual uncontrolled emissions of VOCs in the DMNFR area. That exemption continues to apply to Sections XII.B. through XII.I., but is not extended to Sections XII.J., XII.K., and XII.L.

Definitions (Sections XII.B. and XVII.A.)

The Commission is adopting definitions into Section XII.B., most of which are consistent with the existing definitions of Section XVII.

In the definition of “component”, the Commission is clarifying both in Section XII.B. and in Section XVII.A., that thief hatches and other openings on storage tanks are included in the definition as a pressure relief device. This revision clarifies that leaks can occur from the thief hatch (e.g., faulty or dirty seals) that are different than vented emissions under the standard in Section XVII.C.2.a., and that such leaks are subject to the LDAR program. The Commission anticipates that emissions from storage tanks identified as leaks requiring repair through the LDAR inspections under Sections XII.L. or XVIII.F. will be recorded and reported as leaks starting in 2018 for the 2019 annual report.

The Commission is adding a definition of “custody transfer” that applies to custody transfers of both natural gas and oil products. The Commission is also adding definitions for “natural gas driven diaphragm pump” and “natural gas processing plant” that correspond to federal definitions.

Operate without venting clarification (Section XVII.C.2.a.)

The Commission is providing additional detail concerning provisions adopted in 2014 that established an “operate without venting” standard for storage tanks. In response to industry concern that Section XVII. does not sufficiently define “venting” or delineate “venting” from “leaking,” the Commission is adopting provisions clarifying which emissions from storage tanks are considered “venting”. Section XVII.F. defines “leaking” in terms of infra-red camera or EPA Method 21 inspections of components. While storage tanks may also have leaks, as the Commission recognizes by including thief hatches or other openings on storage tanks in the definition of component, the Commission now further clarifies the “venting” standard by specifying that “venting” is emissions that are primarily the result of over-pressurization or that are from an open or visibly unseated pressure relief device (e.g., thief hatch). The Commission intends that “visibly unseated” means visible from the outside of the pressure relief device and does not require an owner or operator to open a pressure relief device to determine if the seal is proper. The Commission also authorizes the Division to request a demonstration from the owner or operator that “venting” emissions observed by the Division were not primarily the result of over-pressurization. The Commission intends that such demonstration request allow an owner or operator to provide case specific information or other sufficient details that the design, operation, and maintenance of the facility is adequate to prevent over-pressurization. In clarifying a difference between “leaking” and “venting,” the Commission does not prohibit component leaks, per se, so long as leaks are repaired under the applicable repair time frames but does continue to prohibit “venting” from storage tanks.

Ozone season clarification (Sections XII.F.4. and XII.H.6.)

In October 2015, the EPA finalized a revision to the ozone NAAQS. (80 Fed. Reg. 65292 (Oct. 26, 2015)). In publishing its final rule, the EPA revised the length of Colorado's ozone season. Colorado's ozone season is now year-round, rather than the months of May through September. The Commission therefore revised references to "ozone season" in Sections XII.F.4. and XII.H.6. to reflect that the requirements now apply during the months of May to September. There are no substantive changes to the underlying requirements resulting from this revision.

Equipment leaks at natural gas processing plants (Section XII.G.)

The Commission is updating the LDAR program applicable to equipment leaks at natural gas processing plants in the DMNFR by requiring owners or operators to comply with 40 C.F.R. Part 60 (NSPS), Subparts OOOO or OOOOa instead of complying with NSPS Subpart KKK, which is an earlier NSPS and less stringent. Subpart KKK requires sources to implement a NSPS Subpart VV level LDAR program, while Subpart OOOO requires sources to implement a NSPS Subpart VVa level LDAR program. A Subpart VVa level LDAR program is recommended for equipment at natural gas processing plants in the Oil and Gas CTG. The Commission determined that a 2019 implementation date would provide owners and operators of existing natural gas processing plants a reasonable period of time to establish and obtain the necessary resources to transition from Subpart KKK to Subpart OOOO LDAR requirements.

Compressors (Section XII.J.)

The Commission is adopting the centrifugal and reciprocating compressor provisions from existing Section XVII.B.3. into new Section XII.J. in order to include the requirements in Colorado's Ozone SIP. The Commission is expanding the existing reciprocating compressor requirements to reciprocating compressors located at natural gas processing plants to address recommendations in the Oil and Gas CTG. Owners or operators of existing reciprocating compressors at natural gas processing plants must begin monitoring the reciprocating compressor hours of operation on January 1, 2018, starting at zero, in relation to the rod packing replacement requirement, conduct the first rod packing replacement prior to January 1, 2021, or route emissions to a process beginning May 1, 2018.

The Commission intends to allow owners or operators the option to reduce VOC emissions by routing centrifugal compressor emissions to a process or control and reciprocating compressor emissions to a process, consistent with the recommendations in the Oil and Gas CTG. With respect to centrifugal compressors, the Oil and Gas CTG and related federal requirements reveal that "process" generally refers to routing emissions via a closed vent system to any enclosed portion of a process unit (e.g., compressor or fuel gas system) where the emissions are predominantly recycled, consumed in the same manner as a material that fulfills the same function in the process, transformed by chemical reaction into materials that are not regulated materials, incorporated into a product, or recovered. Similarly, with respect to reciprocating compressors, routing to a process includes using a rod packing emissions collection system that operates under negative pressure and meets cover and closed vent system requirements. The negative pressure requirement ensures that all emissions are conveyed to the process and avoids inducing back pressure on the rod packing and resultant safety concerns. The Commission recognizes that there may be a distinction between air pollution control equipment and process equipment (see e.g., U.S. EPA Letter to Timothy J. Mohin RE: Criteria for Determining Whether Equipment is Air Pollution Control Equipment or Process Equipment (Nov. 27, 1995)). For example, as noted in the Oil and Gas CTG, vapor recovery units and flow lines that "route emissions to a process" may be considered part of the process and not a control device, however, a related cover and closed vent system, if present, are still subject to applicable requirements. Further, components (as defined in these rules) located within a process or that are part of process equipment are subject to the Section XII.L. LDAR requirements. The Commission intends that owners or operators will follow similar procedures when complying with centrifugal and reciprocating compressor requirements in Section XII.J.

The Commission has adopted an inspection program for compressors, but also intends to provide owners or operators with the alternative of complying with other requirements, including the LDAR program adopted into Section XII.L. While the requirements of the LDAR program would replace the annual visual inspections and EPA Method 21 inspections of the cover and closed vent systems for defects and leaks, owners or operators would still need to conduct monthly inspections of their combustion devices. Compliance with the LDAR program is not limited to the inspection frequency and methods specified therein; owners or operators will also need to maintain records of the inspections and submit reports to the Division, consistent with the requirements of the LDAR program.

The Commission has specified an inspection and repair schedule for compressors, but has recognized that there may be reasons that a system is unsafe or difficult to inspect, or where a repair may not be feasible. Owners or operators will need to maintain records of each cover or closed vent system that is unsafe or difficult to inspect and schedule for inspection when circumstances allow. Similarly, when a repair is infeasible, insofar as it would require a shutdown of the equipment, repair can be delayed until the next scheduled shutdown but must be completed within two years after discovery. The Commission expects owners or operators to attempt to confirm repair before starting up operation after shutdown, to the extent practicable. The Commission also expects that if the repair attempt can be made during an unplanned shutdown, it will be.

The Commission adopts the monitoring and recordkeeping requirements to ensure and demonstrate compliance with the control requirements.

As an alternative to complying with the control, monitoring, and recordkeeping requirements in Section XII.J., owners or operators may instead comply with centrifugal or reciprocating compressor control, monitoring, recordkeeping, and reporting requirements in a NSPS, including Subparts OOOO, OOOOa, or future standards.

Natural gas driven diaphragm pumps (Section XII.K.)

The Oil and Gas CTG contains recommendations for RACT for natural gas-driven diaphragm pumps. The Commission has not previously adopted regulations specifically directed at this type of equipment, and does so in Section XII.K.

The Oil and Gas CTG recommends that the pumps located at a natural gas processing plant have zero VOC emissions. The Oil and Gas CTG also recommends that owners or operators of pumps located at well sites route VOC emissions from the pneumatic pump to an onsite control device or process, unless the pneumatic pump operates on fewer than 90 days or an engineering assessment shows that routing the pneumatic pump emissions to a control device or process is technically infeasible. The assessment of technical feasibility may include safety considerations, distance from the control device, pressure losses and differentials in the closed vent system, gas pressure, and the capacity of the control device, among other things. The Commission acknowledges that RACT, by EPA definition, includes both technological and economic feasibility elements. The Commission determined that the cost of routing pneumatic pump emissions to an existing control device or process is reasonable and is, therefore, only providing an exemption from the emission control requirement based on technical infeasibility. However, the Commission does not intend to limit future RACT determinations due to limiting the pneumatic pump infeasibility analysis to technical ability. In addition, the 90-day exemption for pumps was included to address intermittently used or portable pumps. Consistent with the Oil and Gas CTG, the Commission intends that if a pump operates on any period of a calendar day, that day would be included in the calculation for applicability of the 90-day exemption.

The Commission does not expect an owner or operator to install new equipment specifically to route pneumatic pump emissions to a control or process but intends that when an owner or operator subsequently otherwise installs a control device or it becomes technically feasible to route pump emissions to a process, then the owner or operator will capture the emissions from the pneumatic pump and route the emissions to the newly installed control device or feasible process. Routing to a control or process generally refers to routing the emissions through a closed vent system to a vapor recovery unit, combustion device, or enclosed portion of a process where emissions are recycled and/or consumed.

The Commission has applied the same flexibility for pneumatic pumps as it has for compressors; owners or operators may comply with the inspection requirements in Section XII.K. or may follow the LDAR program in Section XII.L. Also similar to compressors, owners or operators may delay subsequent repair attempts of equipment where, during a scheduled shutdown, the owner or operator unsuccessfully repaired the leak or equipment requiring repair so long as repair is completed within two years after discovery. As with compressors, the Commission expects owners or operators to attempt to confirm repair before starting up operation after a shutdown and make an attempt to repair during unscheduled shutdowns, to the extent practicable.

As an alternative to complying with the control, monitoring, recordkeeping, and reporting requirements in Section XII.K., owners or operators may instead comply with pneumatic pump emission control, monitoring, recordkeeping, and reporting requirements in a NSPS, including Subparts OOOO, OOOOa, or future standards.

Fugitive emissions at well production facilities and natural gas compressor stations (Section XII.L.)

The Oil and Gas CTG recommends LDAR programs at well sites (*i.e.*, well production facilities) and gathering and boosting stations (*i.e.*, natural gas compressor stations), including inspection frequencies, recordkeeping, and reporting. The Commission established Colorado's well production facility and natural gas compressor station LDAR program in 2014 in Section XVII.F., which is not part of the Ozone SIP. In creating a LDAR program in the Ozone SIP, the Commission intends to maintain as much of the current program as feasible. Where the Commission adopted revisions in Section XII.L. that differ from language currently found in the State Only LDAR program, the Commission in most cases made the same or similar revisions to the corresponding provisions in Section XVII.F.

Inspection, repair, and remonitoring

The Oil and Gas CTG recommends LDAR inspections at a minimum quarterly frequency for gathering and boosting stations and a minimum semi-annual frequency for well sites. The Commission is adopting inspection frequencies to address those recommendations in Section XII.L. The Commission is not modifying the LDAR schedules in Section XVII.F. The Commission intends that for those sources required by Section XVII.F. to conduct more frequent LDAR monitoring than specified in Section XII.L., the owner or operator may comply with Sections XII L.1. and XII.L.2. by complying with Sections XVII.F.3. and XVII.F.4. As with the LDAR inspection frequency in Section XVII.F., the Commission expects that owners or operators will ensure that inspections are appropriately spaced on the frequency schedules (*e.g.*, quarterly inspections will occur every three months but not, for example, on March 31 and April 1).

The Oil and Gas CTG does not recommend a semi-annual LDAR inspection frequency at well sites with a gas to oil ratio less than 300 and which produce, on average, less than or equal to 15 BOE per well per day. The Commission recognizes that a component of RACT is balancing the emission reductions with the cost of the controls, and agrees that there should be a floor below which the recommended minimum frequency does not apply. The Commission determined a threshold of one tpy VOC emissions addresses this balance and the recommendation in the Oil and Gas CTG. Adopting an emissions based threshold maintains consistency with the current Regulation Number 7 applicability program and promotes the clarity and effectiveness of the regulation.

The Commission determined that annual LDAR inspections of well production facilities with uncontrolled actual VOC emissions greater than or equal to one tpy and equal to or less than six tpy and semi-annual LDAR inspections of well production facilities with uncontrolled actual VOC emissions greater than six tpy address the Oil and Gas CTG's recommendations.

The Commission understands that the revised inspection frequencies will result in a significant number of new inspections. However, annual LDAR inspections of well production facilities with uncontrolled actual VOC emissions greater than or equal to one tpy and equal to or less than six tpy will be less burdensome than semi-annual inspections. The Commission has determined that the emission reductions achieved by this program will improve the ability of the DMNFR area to attain the ozone standard and are cost-effective. While the rule specifies that the new inspection frequencies begin to apply as of June 30, 2018, the rule does not require that the first periodic inspection be completed by June 30, 2018. The Commission also does not require that monitoring be conducted in advance of this date; however, inspections done after January 1, 2018, that are in addition to current required LDAR monitoring frequencies may count towards the first annual or semi-annual inspection, or inspections done in the previous quarter at natural gas compressor stations. The Commission encourages owners or operators to conduct inspections prior to the 2018 summer ozone months to more effectively take advantage of the resulting emission reductions.

To ensure that the Ozone SIP LDAR program in Section XII.L. works with the existing State Only LDAR program in Section XVII.F., the Commission has maintained the same thresholds for identifying leaks that require repair. While the Oil and Gas CTG employs a methane concentration threshold when detected with EPA Method 21, Colorado's LDAR program uses a hydrocarbon concentration threshold. The Commission has also revised Section II. to clarify that Section XII.L. includes the use of hydrocarbons as an indicator of VOC emission reductions.

Concerning the use of non-quantitative instrument monitoring methods, the Commission adopted a quality assurance requirement that owners or operators maintain and operate such devices according to manufacturer recommendations. This requirement corresponds to recommendations in the Oil and Gas CTG concerning the maintenance and operation of OGI uses to detect fugitive emission components. The Commission intends for the Division to work with owners or operator to address any concerns that arise from manufacturer specifications for the maintenance of non-quantitative instrument monitoring methods.

Consistent with the current LDAR program in Section XVII.F., the Commission adopted a requirement to make a first attempt to repair an identified leak within five working (*i.e.*, business) days of discovery. In both Section XII.L. and in Section XVII.F., the Commission has included a requirement that repairs be completed within 30 days unless one of the existing justifications for delay of repair applies. As with compressors and pneumatic pumps, owners or operators may delay subsequent repair attempts of equipment where, during a scheduled shutdown, the owner or operator unsuccessfully repaired the leak requiring repair so long as repair is completed within two years of discovery. The Commission has also maintained the flexibility of the State Only LDAR program in the SIP by giving owners or operators detecting leaks with a non-quantitative method (*e.g.*, IR camera) the ability to quantify the leaks within five working days. If the quantification shows that the leak must be repaired under Section XII.L.5., the deadline to repair runs from the date of discovery, not from the date of quantification.

As it did for Section XVII.F.7.c. in 2014, the Commission has also memorialized its intent, in Section XII.L.5.c., that operators not be subject to enforcement for leaks so long as operators are complying with the LDAR program requirements. However, as it also explained in 2014, the Commission does not intend to relieve owners or operators of the obligation to comply with the general requirements of Section XII.C. For example, closing an open thief hatch within five days of an LDAR inspection does not shield an owner or operator from a possible violation of the requirement to minimize emissions to the maximum extent practicable.

Similarly, the Commission does not intend to relieve owners or operators of the obligation, on a State Only basis, to comply with the requirements of Section XVII., including the requirements in Sections XVII.B. and XVII.C.2. to minimize leakage to the extent reasonably practicable and operate without venting, respectively. However, the Commission does not intend these State Only provisions be enforceable under the Ozone SIP.

Recordkeeping and reporting

The Commission has determined that the current requirements did not adequately incentivize owners or operators to make all reasonable good faith efforts to obtain parts necessary to complete repairs. As a result, some leaks continued on delay of repair lists for an unreasonable length of time. Therefore, the Commission has determined that a review and record of such delays by a representative of the owner or operator is necessary for those occasions where unavailable parts have resulted in a delay of repair beyond 30 days.

The Commission expanded the recordkeeping for repair dates to include records of the type of repair method applied. The Commission determined this recordkeeping element aligns with recommendations in the Oil and Gas CTG and will more accurately inform repair activities. The Commission intends for the Division to work with owners and operators to establish a generally standardized set of different types of repair to ensure that owners and operators are consistently recording the information required.

The Commission also expanded the requirements for the annual LDAR report to ensure that the data submitted to the Division more accurately represents and summarizes the activities and effectiveness of the LDAR program. The Commission intends that the LDAR reports include the number of inspections, leaks requiring repair, leaking component type, and monitoring method by which the leaks were found – broken out by facility type (*i.e.*, inspection frequency tier of well production facility or natural gas compressor station).

The Commission intends that both the SIP and State Only LDAR reporting requirement can be satisfied by one report. The Commission expects that the first annual report containing the information required by these revisions will be submitted by May 31, 2019 (*i.e.*, no changes are expected to current requirements for the May 31, 2018, annual report representing leak detection and repair activities conducted during 2017).

Alternative approved instrument monitoring method ("AIMM")

The Commission has adopted a process for the review and approval of alternative instrument monitoring methods. The CAA prohibits a state from modifying SIP requirements except through specified CAA processes. EPA interprets this CAA provision to allow EPA approval of SIP provisions that include state authority to approve alternative requirements when the SIP provisions are sufficiently specific, provide for sufficient public process, and are adequately bounded such that EPA can determine, when approving the SIP provision, how the provision will actually be applied and whether there are adverse impacts. (State Implementation Plans: Response to Petition for Rulemaking; Restatement and Update of EPA's SSM Policy Applicable to SIPs; Findings of Substantial Inadequacy; and SIP Calls to Amend Provisions Applying to Excess Emissions During Periods of Startup, Shutdown and Malfunction, 80 Fed. Reg. 33917-33918, 33927 (June 12, 2015)) Therefore, the Commission includes an application and review process in the SIP for the potential approval of instrument monitoring methods as alternatives to an infrared camera or EPA's Method 21. The approval may also include modified recordkeeping and reporting requirements based on the capabilities of the potential alternative instrument monitoring method. This proposed process does not alter the stringency of Colorado's well production facility and natural gas compressor station LDAR program because an alternative AIMM must be capable of reducing emissions through the detection and repair of leaks comparable to the leaks detected and repaired as specified in the SIP to be potentially approvable.

The Commission received comments from stakeholders requesting that the Commission explicitly provide for the ability to employ certain alternatives not equipped with the leak detection capabilities of infra-red cameras or Method 21. These stakeholders emphasized that monitoring technologies are evolving rapidly and new technologies and monitoring programs are being developed that, when used on their own or in conjunction with other methods, may provide the same or better leak detection and repair results, at potentially lower costs. The process outlined in Section XII.L.8. requires an applicant to demonstrate that the proposed alternative monitoring achieves emission reductions that are at least as effective as the leak detection and repair program in Section XII.L. The Commission intends that the rule be flexible enough to allow the Division to consider such alternative monitoring methods or programs, as long as the applicant can demonstrate that the proposed method or program achieves emission reductions that are as effective as other approved technologies or methods. To make this demonstration, an applicant may consider demonstrating that a program of alternative inspection frequencies, pollutants detected, or leak thresholds for repair achieves emission reductions comparable to the inspection frequencies and leaks requiring repair thresholds in Section XII.L., thus the consideration of an alternative leak detection program. The Commission recognizes that current, established approaches or methodologies to evaluate the performance of alternative monitoring technologies and programs as compared to baseline monitoring technologies (infra-red camera, EPA Method 21) do not yet exist. However, such methodologies are being developed.

For example, the Interstate Technology and Regulatory Council (ITRC), in which Colorado participates, is developing, but has not yet published, a guidance document to establish, if possible, a consensus for evaluating and comparing the effectiveness of leak detection technologies. While the criteria for evaluating the effectiveness of an alternative program as compared to the base program is being developed, alternative monitoring method applicants may submit an application for approval of an alternative monitoring method but must be prepared to present a robust and complete evaluation of the technology or program's performance that allows for comparison to the base technologies in the SIP. It is possible the Division may delay consideration and final determination regarding an alternative monitoring method or program application until established comparison criteria are developed or submitted. Taking into account the deliberations of the ITRC process, the Commission expects that the Division will consider complete applications in a timely manner.

The Commission also received comments from stakeholders requesting that the Commission clarify EPA's participation regarding potential alternative monitoring methods. As discussed above, the Commission believes that the process to review and potentially approve alternative monitoring methods is sufficiently constrained such that EPA, when approving the process, can be assured as to what emission reductions any such alternative monitoring will achieve in the context of the Section XII.L. LDAR program. However, the Commission also recognizes EPA's technical knowledge and is requiring the Division to continue to engage with EPA concerning alternative monitoring methods. Specifically, the Division must provide complete applications to EPA early in the review process, which has previously ranged from three to nine months. The Division must also provide EPA six (6) months after approval of an alternative for further EPA review. The Commission believes this process provides sufficient time for meaningful engagement with EPA.

Clarifications

The Commission is clarifying, both in Section XII.L. and Section XVII.F., that all detected emissions are leaks, but that only those leaks above specified thresholds require repair. The Commission did not intend that leaks falling below the specified thresholds would not be considered "leaks," only that those leaks did not require repair in accordance with the prescribed schedules. The Commission has further clarified that only records of leaks requiring repair need to be maintained.

Regulation Number 7 already requires that owners or operators remonitor repaired leaks with an AIMM. AIMM includes EPA Method 21, which includes the soapy water method, and the Commission further clarifies that an owner or operator may use the soapy water method in EPA Method 21 to remonitor a repaired leak.

Some stakeholders asked the Commission to “clarify” that the LDAR repair, remonitoring, recordkeeping, and reporting requirements applied only to those leaks discovered by the owner or operator, and not those discovered by the Division. The Commission believes that would not be a clarification, but a change to the current program, and does not make that requested revision at this time. Therefore, the repair, remonitoring, recordkeeping, and reporting requirements continue to apply to leaks discovered by the Division.

Pneumatic controllers (Section XVIII.)

The Commission is adopting both Ozone SIP and State Only revisions to Section XVIII.

The Commission added definitions of continuous bleed and intermittent pneumatic controller. The Commission also added “continuous bleed” to several provisions throughout Sections XVIII.C. through XVIII.E. to clarify that the provisions adopted in 2014 primarily applied to continuous bleed pneumatic controllers (which emit continuously) as opposed to intermittent pneumatic controllers (which emit only when actuating).

Pneumatic controllers at or upstream of natural gas processing plants

Section XVIII. already requires that owners or operators install low-bleed pneumatic controllers at or upstream of natural gas processing plants, unless a high-bleed pneumatic controller is required for safety or process purposes. This requirement is consistent with the Oil and Gas CTG and the Commission intends that these provisions be included in Colorado’s Ozone SIP.

The Commission adopts additional requirements, consistent with the Oil and Gas CTG, related to pneumatic controllers at natural gas processing plants. The Commission is requiring that all continuous bleed, natural gas-driven pneumatic controllers at a natural gas processing plant have a bleed rate of zero (*i.e.*, no VOC emissions), unless a pneumatic controller with a bleed rate greater than zero is necessary due to safety and process reasons. To satisfy this requirement, owners or operators of natural gas processing plants could, for example, drive pneumatic controllers with instrument air, use mechanical or electrically powered pneumatic controllers, or use self-contained pneumatic controllers that release natural gas to a downstream pipeline instead of to the atmosphere. The requirements to submit a justification for a pneumatic controller exceeding the emission standard to the Division, as well as the requirements for tagging and records, duplicate and are intended to be consistent with existing requirements related to high-bleed pneumatic controllers. The requirement to maintain pneumatic controllers exceeding the applicable emission standard are also duplicated from the existing high-bleed maintenance requirement, but revised to include the suggested maintenance actions specifically in the applicable provisions, instead of referring to an “enhanced maintenance” definition. The Commission revised the maintenance requirement in this manner to separate the actions taken to maintain a pneumatic controller exceeding the applicable emission standard from the, potentially very similar, actions taken to return a pneumatic controller to proper operation. For example, the owner or operator of a high-bleed pneumatic controller or a pneumatic controller with a bleed rate greater than zero at a natural gas processing plant is required to perform specified maintenance on the pneumatic controller regardless of whether or not the pneumatic controller is determined to be properly operating. In contrast, the owner or operator of a pneumatic controller inspected under Section XVIII.F. must conduct enhanced response to return that pneumatic controller to proper operation.

Additionally, the Commission is requiring owners or operators to maintain records demonstrating their continuous bleed, natural gas-driven pneumatic controllers meet the applicable low-bleed or bleed rate of zero standards. These records are also intended to inform the extent to which continuous bleed pneumatic controllers are used in the DMNFR. The Commission understands that the number of continuous bleed, natural gas-driven pneumatic controllers in use by an operator can change frequently, and is not requiring a running log or count of each individual pneumatic controller.

The Commission adopted these recordkeeping requirements with the expectation that owners or operators can keep records including, but not limited to, site-specific documentation of continuous bleed, natural gas-driven pneumatic controllers such as manufacturer specifications, engineering calculations, field test data, or documentation of a company's continuous bleed, natural gas-driven pneumatic controller purchase and installation program ensuring that any such pneumatic controller meets the applicable bleed rate standard.

Clarification

The Commission is also clarifying the intent behind provisions adopted in 2014 regarding the use of pneumatic controllers powered by instrument air (as opposed to natural gas) when grid power is being used. In 2014, the Commission intended that when a pneumatic controller was proposed for installation, owners or operators would power the pneumatic controller via electrical power instead of natural gas when electrical grid power was being used on-site. The provisions adopted in 2014 allowed owners or operators to install a pneumatic controller with VOC emissions equal to or less than a low-bleed pneumatic controller in some situations. The Commission has learned that some owners or operators interpret the rule as providing the option of installing either no-bleed or low-bleed pneumatic controllers in all situations.

Even though the Commission believes its intent was clear, the Commission recognizes that the rule could fairly be described as ambiguous and that there is a good faith legal argument for the alternative interpretation. The Commission is revising the rule to clarify that where electric grid power is being used on site and it is technically and economically feasible to install no-bleed pneumatic controllers, any newly installed pneumatic controllers must be no-bleed. Where the owner or operator determines it is not technically and economically feasible to install a no-bleed pneumatic controller, the owner or operator may install a low-bleed or intermittent pneumatic controller.

The Commission recognizes that the installation of an electrically-powered controller may have been feasible in 2014, but may not be feasible to retrofit at this time. The Commission nonetheless encourages owners or operators statewide who, based on a misreading of the regulation, did not install a no-bleed pneumatic controller to evaluate whether retrofitting controllers – with no-bleed or self-contained pneumatic controllers – at this time is technically and economically feasible. The Commission also encourages owners and operators statewide to install, or retrofit with, no-bleed or self-contained pneumatic controllers at locations across the state, even where on site electrical grid power is not available to the extent there is no significant air quality disbenefit in doing so.

Natural gas driven pneumatic controller inspection and enhanced response (State Only)

Following the 2014 rulemaking, the Commission requested that the Division continue its investigation into potential regulations for intermittent pneumatic controllers. During the recent 2016 ozone rulemaking, stakeholders again asked the Commission to address intermittent pneumatic controllers. In response, the Commission again directed the Division to evaluate potential emission reduction measures for intermittent pneumatic controllers.

The Commission is adopting an inspection and enhanced response (e.g., maintenance) program for natural gas-driven pneumatic controllers. While the Oil and Gas CTG notes the value of pneumatic controller inspection and maintenance, the Oil and Gas CTG does not specify a pneumatic controller inspection and maintenance as presumptive RACT. Therefore, while the Commission determined that these revisions are technically and economically feasible, the revisions are proposed as State Only in the DMNFR and are not made part of the Ozone SIP at this time. Natural gas-driven pneumatic controllers include continuous bleed, intermittent, and self-contained pneumatic controllers. Recent studies of pneumatic controllers have found that malfunctioning devices contribute a significant amount of hydrocarbon emissions to the atmosphere.

The Oil and Gas CTG suggests that maintenance of pneumatic controllers, including cleaning and tuning, can eliminate excess emissions from the devices. While the Oil and Gas CTG's recommended RACT (low-bleed or zero emissions) applies to continuous bleed, natural gas-driven pneumatic controllers, the discussion concerning enhanced maintenance of pneumatic controllers builds on earlier EPA discussions, such as EPA's 2014 Pneumatic Controller White Paper, and is not limited to continuous bleed pneumatic controllers. The Commission recognizes that continuous bleed and intermittent pneumatic controllers are designed to have emissions, however these pneumatic controllers can also have excess emissions when not operating properly. As a result, the Commission believes that a pneumatic controller inspection and response program will reduce the excess emissions from such pneumatic controllers.

The Commission intends to apply the same find and fix approach used in the LDAR requirements in Sections XII.L. and XVII.F. to all natural gas-driven pneumatic controllers in the DMNFR. The Commission is requiring that natural gas-driven pneumatic controllers at well production facilities and natural gas compressor stations in the DMNFR be inspected periodically to determine whether the pneumatic controller is operating properly, in contrast to quantitatively comparing pneumatic controller emissions to a regulatory threshold. The Commission is requiring that owners or operators inspect pneumatic controllers at well production facilities annually, semi-annually, quarterly, or monthly, depending on the well production facility VOC emissions, and at natural gas compressor stations quarterly or monthly, depending on the natural gas compressor station fugitive emissions.

The Commission expects that owners or operators will inspect their pneumatic controllers during the same LDAR inspections, and using the same AIMM, conducted for compliance with Sections XII.L. or XVII.F. The pneumatic controller inspection and enhanced response process is intended to be a multi-step process. First, the owner or operator must inspect all natural gas-driven pneumatic controller using AIMM to screen for detectable emissions. This first step allows owners or operators to narrow potential response efforts to only those pneumatic controllers with detected emissions. Second, the owner or operator must determine whether the pneumatic controllers with detected emissions are operating properly. Use of an AIMM is not required during this second step; the Commission does not at this time intend to mandate to owners or operators how to determine if their pneumatic controllers are operating properly. During this second step, if an owner or operator determines that the pneumatic controller is operating properly, no further action is necessary. Third, where an owner or operator determines the pneumatic controller is not operating properly, the owner or operator must take actions to return an improperly operating pneumatic controller to proper operation. Fourth, general recordkeeping and reporting requirements apply broadly to the number of facilities inspected and number of inspections. More detailed recordkeeping and reporting is required for those pneumatic controllers that the owner or operator determined not to be operating properly.

Similar to the LDAR records, owners or operators must keep records of the date the pneumatic controller was returned to proper operation and a description of the types of actions taken. As with well production facility and natural gas compressor station LDAR records, the Commission intends for the Division to work with owners and operators to establish a generally standardized set of different types of response actions to ensure that owners and operators are consistently recording the information required. The Commission expects that owners or operators will include the pneumatic controller information as State Only information in their LDAR annual reports. In returning a pneumatic controller to proper operation, the Commission relies upon the previously defined term, now enhanced response, found in Section XVIII.B. related to maintaining high-bleed pneumatic controllers. The Commission has expanded this definition to guide responsive activities concerning all natural gas-driven pneumatic controllers. Recognizing that the function and potential maintenance or repair of pneumatic controllers can be variable, owners or operators are not restricted to using an AIMM to determine proper operation or verify the return to proper operation.

The Commission has adopted a “reassessment” provision for this inspection and enhanced response program following a Division led study of pneumatic controller emission reduction options, including the rate, type, application, and causes of pneumatic controllers found operating improperly; inspection and repair techniques and costs; available preventative maintenance methods; appropriateness of the definitions of enhanced response, intermittent pneumatic controller, no-bleed pneumatic controller, self-contained pneumatic controller, and pneumatic controller; and other related information. The Commission also recognizes that owners and operators may currently have limited information on “good engineering and maintenance practices” for pneumatic controllers and intends that more information on these practices will be gathered during the pneumatic study and implementation of Section XVIII.F. to inform the reassessment of the inspection and enhanced response program. The data collection effort will include data from a representative cross-section of well production facilities and natural gas compressor stations in the DMNFR. In accordance with industry’s proposal, a task force will be convened by January 30, 2018, consisting of representatives from industry, the Division, local governments, environmental groups, and other interested parties. Data collection will begin no later than by May 1, 2018. The task force will brief the Commission annually and make any recommendations on its findings in a report to the Commission, due May 1, 2020. The Commission intends that the Division, industry, local government, and environmental group task force participants each have the opportunity to contribute to the final report and provide one representative to speak during the briefings to the Commission. The Commission intends that this information be used to reassess the natural gas-driven pneumatic controller requirements of Section XVIII.F. Section XVIII.F. will remain in effect until rescinded, superseded, or revised.

The Commission recognizes that there is much to learn about the inspection and maintenance of natural gas-driven pneumatic controllers, which highlights the need for the reassessment of Section XVIII.F. as well as enforcement discretion. The Commission intends that while the task force is actively working on data collection and the 2020 report to the Commission, the determination of whether a pneumatic controller is operating properly will be made by the owner or operator. Any information gathered through the task force, including on preventative, good engineering, and maintenance practices, will be used to reassess Section XVIII.F. and will not be used for enforcement purpose through 2020.

Additional Considerations

Colorado must revise Colorado’s Ozone SIP to address the ozone Moderate nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. The Commission carefully considered what provisions to include in Colorado’s Ozone SIP, especially given Colorado’s pre-existing emission control requirements that address most of the same sources addressed by the Oil and Gas CTG, yet do so differently. Some of these pre-existing requirements were adopted into Colorado’s SIP and some will remain as State Only requirements. In determining what existing provisions would be included in Colorado’s Ozone SIP, the Commission considered: 1) whether or not Colorado had existing emission control measures for the same sources covered by the Oil and Gas CTG; 2) whether these existing requirements were already adopted for inclusion in the Ozone SIP; and 3) the degree of emissions reductions achieved by any existing Colorado emission control measures in comparison to the Oil and Gas CTG. In resolving differences between existing Colorado provisions and the Oil and Gas CTG, preference was given to existing Colorado provisions, especially those already incorporated into Colorado’s Ozone SIP and Colorado’s existing regulatory framework. For example, the Commission relied upon existing storage tank requirements already adopted into Colorado’s Ozone SIP. In the case of well production facility LDAR, the Commission adopted a tpy applicability threshold in place of the Oil and Gas CTG’s BOE threshold, which applies to more sources than the Oil and Gas CTG, yet adopted a less frequent inspection frequency into the Ozone SIP for the smaller facilities than the Oil and Gas CTG.

In determining whether or not any additional requirements would be relied upon in establishing RACT in Colorado's Ozone SIP for the oil and gas sector, the Commission determined whether or not the emission control measures were necessary for the ozone attainment demonstration. In the case of LDAR for pneumatic controllers at well production facilities and natural gas compressor stations, the Commission adopted emission control measures as State Only measures given the need to obtain emission reductions as well as more information on this source type. These examples illustrate the Commission's careful consideration of what provisions to include in Colorado's Ozone SIP.

The CAA requires that Colorado's Ozone SIP include RACT for all sources covered by a CTG, such as the emission sources addressed in the Oil and Gas CTG. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's Moderate nonattainment area obligations, including those related to RACT. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs.

The Commission is also revising certain State Only regulations to reduce emissions and promote attainment of current federal ozone standards. Specifically, the Commission is adopting requirements related to the inspection of natural gas-driven pneumatic controllers at oil and gas facilities. As discussed above, malfunctioning pneumatic controllers can result in significant hydrocarbon emissions. The DMNFR ozone nonattainment area is currently classified as a Moderate nonattainment area under the 2008 ozone NAAQS. The deadline for the DMNFR to attain the 2008 ozone NAAQS is July 2, 2018. If the DMNFR does not attain the standard or does not receive an extension, EPA may reclassify the DMNFR as a Serious nonattainment area under the 2008 ozone NAAQS. In addition, the Commission approved a designation recommendation for the DMNFR under the 2015 ozone NAAQS in September 2016.

While EPA has not yet acted on this recommendation, the Commission expects the DMNFR will be designated as nonattainment under the 2015 ozone NAAQS and is taking action to promote attainment of the more stringent standard. Given both the potential for a reclassification to Serious under the 2008 ozone NAAQS and the need to reduce ozone to meet the more stringent 2015 ozone NAAQS, the Commission is adopting the State Only pneumatic controller inspection requirements that further reduce ozone precursors emissions, notwithstanding the fact that a pneumatic controller inspection program is not specified as presumptive RACT in the Oil and Gas CTG.

In accordance with C.R.S. § 25-7-110.5(5)(b), the Commission determines:

- (I) CAA Sections 172(c) and 182(b) require that Colorado submit a SIP that includes provisions requiring the implementation of RACT at sources covered by a CTG. The EPA issued the final Oil and Gas CTG in October 2016, leading to the revisions to the Ozone SIP adopted by the Commission. The EPA revised the ozone NAAQS in 2015 and the DMNFR must attain the new standard or face additional requirements. The revisions to Regulation Number 7 address RACT for compressors, pneumatic pumps, pneumatic controllers, natural gas processing plants, natural gas compressor stations, and well production facilities. The revisions apply to equipment already regulated by Colorado on a State Only basis and apply to equipment not previously subject to regulation. NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, and NESHAP HHH may also apply to the regulated equipment. The Commission determined that the adopted RACT SIP requirements are comparable to the Oil and Gas CTG's recommendations. The Commission also determined that there are not comparable federal rules requiring the inspection and maintenance of natural gas-driven pneumatic controllers.

- (II) The federal rules discussed in (I), are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold. EPA has also provided some flexibility in NSPS OOOOa to allow an owner or operator to request EPA approve compliance with an alternate emission limitation (e.g., alternative monitoring, state program) instead of related requirements in NSPS OOOOa.
- (III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure timely attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here. Further, the State Only pneumatic controller inspection requirements address the lack of federal requirements concerning emissions from malfunctioning pneumatic controllers.
- (IV) Unless federal law changes, Colorado will be required to comply with the more stringent 2015 ozone NAAQS in the near future and may be required to comply with the more stringent requirements for a Serious nonattainment area. These current SIP and State Only revisions may improve the ability of the regulated community to comply with new, more stringent, future requirements. In addition, these revisions build upon the existing regulatory programs being implemented by Colorado's oil and gas industry, which is more efficient and cost-effective than a wholesale adoption of EPA's recommended oil and gas RACT provisions.
- (V) EPA has established October 27, 2018, deadline for this SIP submission. EPA has not yet established deadlines for the DMNFR to attain the 2015 ozone NAAQS. However, given the potential reclassification of the DMNFR to Serious under the 2008 ozone NAAQS, the Commission determined that taking action to reduce ozone precursor emissions as soon as practicable, either as part of the SIP or on a State Only basis, is warranted.
- (VI) The revisions to Regulation Number 7 Sections XII. and XVIII. strengthen Colorado's SIP and State Only provisions, which currently addresses emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry.
- (VII) The revisions to Regulation Number 7 Sections XII. and XVIII., including the State Only provisions, establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources.
- (VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018, or qualify for an extension of the attainment deadline, EPA will likely reclassify Colorado as a Serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs. The State Only rule revisions are expected to reduce future costs by achieving emissions reductions that will assist the DMNFR in attaining both the 2008 and 2015 ozone NAAQS thus avoiding additional ozone nonattainment area CAA requirements.

- (IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements. The State Only pneumatic controller inspection program is tailored to be consistent with the SIP required LDAR program, thereby reducing costs related to pneumatic controller inspections.
- (X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for compressors, pneumatic controllers, leak detection and repair at well production facilities and natural gas compressor stations, and equipment leaks at natural gas processing plants. Further, pneumatic controller inspections will be conducted using accepted technologies and some owners or operators already repair and maintain pneumatic controllers.
- (XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.
- (XII) Alternative rules could also provide reductions in ozone and help to attain the NAAQS. However, a no action alternative would very likely result in an unapprovable SIP. The Commission determined that the Division's proposal was reasonable and cost-effective. The Commission further determined the State Only natural gas-driven pneumatic controller inspection program is reasonable and cost-effective, given the potential for reducing emissions from malfunctioning pneumatic controllers and the absence of federal requirements addressing pneumatic controller emissions.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's Ozone SIP to address the Moderate nonattainment area requirements. Colorado must also continue to reduce ozone concentrations to address both the possibility of reclassification under the 2008 ozone NAAQS and the 2015 ozone NAAQS. However, to the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, including regulatory changes made on a State Only basis, and after considering all the information in the record, the Commission hereby makes the determination that:

- (I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.
- (II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of the ozone precursors VOC.
- (III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.
- (IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.
- (V) The selected regulatory alternative will maximize the air quality benefits of regulation in the most cost-effective manner.

Q. July 19, 2018 (Sections XVI. and XIX.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

On May 21, 2012, the Denver Metro/North Front Range ("DMNFR") area was designated as Marginal nonattainment for the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"), effective July 20, 2012, with an attainment date of July 20, 2015 (77 Fed. Reg. 30088). On May 4, 2016, the U.S. Environmental Protection Agency ("EPA") published a final rule that determined that DMNFR area failed to attain the 2008 8-hour Ozone NAAQS by the applicable Marginal attainment deadline and therefore reclassified the DMNFR area to Moderate, effective June 3, 2016, and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone season data.

Due to the reclassification, Colorado must submit revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") Moderate nonattainment area requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (See 80 Fed. Reg. 12264 (March 6, 2015)). The SIP revision must include Reasonably Available Control Technology ("RACT") requirements for major sources of VOC and/or NOx (i.e. sources that emit or have the potential to emit 100 tons per year ("tpy") or more). The CAA does not define RACT. However, EPA has defined RACT as the "lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." 44 Fed. Reg. 53762 (Sept. 17, 1979). RACT can be adopted in the form of emissions limitations or work practice standards or other operation and maintenance requirements as appropriate.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., ("Act"), Section 25-7-105(1)(a) directs the Commission to promulgate such rules and regulations necessary for the proper implementation and administration of a comprehensive SIP that will assure attainment and maintenance of national ambient air quality standards. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106(1)(c) and (2) also authorize the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution, and monitoring and recordkeeping requirements. Section 109(1)(a) authorizes the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources of air pollutants.

Purpose

The Regional Air Quality Council ("RAQC") and the Colorado Department of Public Health and Environment, Air Pollution Control Division ("Division") conducted a public process to develop the associated SIP and supporting rule revisions.

In response to the reclassification, the Commission revised Regulation Number 7 to satisfy RACT SIP requirements for Moderate nonattainment areas by establishing categorical RACT requirements for major sources of VOC and/or NOx in the DMNFR. Specifically, the Commission adopted RACT requirements in Section XVI.D. for existing boilers, stationary combustion turbines, lightweight aggregate kilns, glass melting furnaces, and compression ignition reciprocating internal combustion engines ("RICE") (collectively referred to as "stationary combustion equipment") located at major sources of NOx in the DMNFR as of June 3, 2016.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Major VOC and NOx source RACT

Colorado has major sources of VOC and/or NOx in the ozone nonattainment area. The following sources were known by the Commission to be major sources of VOC and/or NOx as of June 3, 2016 and were analyzed in Colorado's Moderate Area SIP for the 2008 8-Hour Ozone NAAQS:

Anheuser-Busch, Fort Collins Brewery (069-0060) and Nutri-Turf (123-0497) (major for VOC and NOx)

Ball Metal Beverage Container Corporation (059-0010 major for VOC)

Buckley Air Force Base (005-0028 major for NOx)

Carestream Health (123-6350 major for NOx)

Cemex Construction Materials (013-0003 major for VOC and NOx)

Colorado Interstate Gas, Latigo (005-0055 major for NOx)

Colorado Interstate Gas, Watkins (001-0036 major for VOC and NOx)

Colorado State University (069-0011 major for NOx)

CoorsTek (059-0066 major for VOC)

Corden Pharma Colorado (013-0025 major for VOC)

DCP Midstream, Enterprise (123-0277 major for VOC and NOx)

DCP Midstream, Greeley (123-0099 major for VOC and NOx)

DCP Midstream, Kersey/Mewbourn (123-0090 major for VOC and NOx)

DCP Midstream, Lucerne (123-0107 major for VOC and NOx)

DCP Midstream, Marla (123-0243 major for VOC and NOx)

DCP Midstream, Platteville (123-0595 major for VOC and NOx)

DCP Midstream, Roggen (123-0049 major for VOC and NOx)

DCP Midstream, Spindle (123-0015 major for VOC and NOx)

Denver Regional Landfill, Front Range Landfill, Timberline Energy (123-0079 major for NOx)

Elkay Wood Products (001-1602 major for VOC)

IBM Corporation (013-0006 major for NOx)

Kerr-McGee Gathering, Frederick (123-0184 major for VOC and NOx)

Kerr-McGee Gathering, Hudson (123-0048 major for VOC and NOx)

Kerr-McGee Gathering, Fort Lupton/Platte Valley/Lancaster (123-0057 major for VOC and NOx)

Kodak Alaris (123-0003 major for VOC)

Metal Container Corporation (123-0134 major for VOC)

Metro/Suez Waste Water Cogeneration Facility (001-0097 major for NOx)

MillerCoors Golden Brewery, Rocky Mountain Metal Container (059-0006), MMI/EtOH (059- 0828), and Colorado Energy Nations Company, LLC (059-0820) (major for VOC and NOx)

Owens-Brockway Glass (123-4406 major for NOx)

Phillips 66 Pipeline, Denver Terminal (001-0015 major for VOC)

Plains End (059-0864 major for VOC and NOx)

Public Service Company, Cherokee (001-0001 major for NOx)

Public Service Company, Denver Steam Plant (031-0041 major for NOx)

Public Service Company, Fort Lupton (123-0014 major for NOx)

Public Service Company, Fort Saint Vrain (123-0023 major for NOx)

Public Service Company, Rocky Mountain Energy Center (123-1342 major for NOx)

Public Service Company, Valmont (013-0001 major for NOx)

Public Service Company, Yosemite (123-0141 major for NOx)

Public Service Company, Zuni (031-0007 major for NOx)

Rocky Mountain Bottle Company (059-0008 major for NOx)

Sinclair Transportation Company, Denver Terminal (001-0019 major for VOC)

Spindle Hill Energy (123-5468 major for NOx)

Suncor Energy, Commerce City Refinery Plants 1, 2, and 3 (001-0003 major for VOC and NOx)

Thermo Cogeneration, JM Shafer (123-0250 major for NOx)

Tri-State Generation, Frank Knutson (001-1349 major for NOx)

TRNLWB, LLC (Trinity Construction Materials, Inc.) (059-0409 major for NO_x)

University of Colorado Boulder (013-0553 major for NO_x)

WGR Asset Holding, Wattenberg (001-0025 major for VOC and NO_x)

Many of the major sources listed above are subject to regulatory RACT requirements. Some of the sources or source emissions points are subject to regulatory RACT requirements in Colorado's SIP; other sources or source emissions points are subject to individual RACT requirements established in federally enforceable permits as a minor source RACT requirement of inclusion of an applicable federal New Source Performance Standards ("NSPS") or National Emission Standard for Hazardous Air Pollutants ("NESHAP"). However, as a Moderate nonattainment area, Colorado must include in the SIP, provisions to implement RACT for Colorado's major sources. During the November 17, 2016 rulemaking, the Commission adopted source specific RACT for a number of major sources of VOC and/or NO_x (again greater than or equal to 100 tons per year) in the DMNFR. These were originally adopted as Sections XIX.C.-XIX.G. for stationary combustion turbines, stationary internal combustion engines, wood furniture manufacturing, and municipal landfills, respectively, during the November 17, 2016 rulemaking. These sections have changed to Sections XVI.D.4.b. and XIX.A.-D. during this July 19, 2018 rulemaking, where requirements for stationary combustion turbines were removed and consolidated into Section XVI.D.4.b. The original Section XIX.C.-XIX.G. RACT requirements became effective on January 1, 2017. However, during the November 17, 2016 rulemaking, the Commission determined that little, if any, additional controls could be implemented by certain major sources by January 1, 2017. The Commission also determined that not all major sources or major source emission points were subject to existing regulatory RACT requirements in Regulation Number 7 or federally enforceable emission limits in Regulation 3, Part F. Therefore, the Commission opted to adopt RACT for Colorado's existing major sources of NO_x on a categorical basis in this July 19, 2018 rulemaking.

Establishing RACT on a categorical basis is a distinctly different process from Colorado's minor source RACT permitting requirement found in Regulation 3, Part B, Section III.D.2. Minor source RACT permitting is specific to new or modified sources (i.e. sources that have already committed to a capital expenditure to construct or modify a process), and the designs of which can more easily accommodate changes prior to construction. Categorical RACT applies much more broadly to source category, including both existing sources/equipment and new/modified sources/equipment. This inclusion of existing equipment significantly impacts costs, as those sources are not already committed to a capital expenditure and any associated shut down to add controls. This ultimately impacts the decision on what controls are determined to be reasonably available, technologically and economically feasible for the source category as a whole. Thus, categorical RACT may in some cases be different from any RACT established for a specific source or piece of equipment under the minor source permitting RACT requirement.

To determine RACT on a categorical basis, the Commission required specific owners or operators to submit a RACT analysis for the facility or specific emission points to the Division by December 31, 2017. In these RACT analyses, sources were required to identify potential options to reduce VOC and/or NO_x emissions from the facility or emission point(s), propose RACT for that facility or point(s), propose associated monitoring, propose a schedule for implementation, and include economic and technical information demonstrating why the proposal established RACT for the particular facility or emission point(s). The following major sources were required to submit RACT analyses:

Anheuser-Busch (069-0060) – emission points equal to or greater than 2 tpy VOC or 5 tpy NO_x

Buckley Air Force (005-0028) – engines and engine test cell (pt 102, 103, 104, 105, 101)

Carestream Health (123-6350) – boilers (pt 004)

Colorado Energy Nations Company, LLC (059-0820) – boilers (pt 001, 002)

Colorado Interstate Gas, Latigo (005-0055) – engines (001, 011)

Colorado Interstate Gas, Watkins (001-0036) – engines (001, 002)

Colorado State University (069-0011) – boilers (pt 003, 005, 007, 013)

IBM (013-0006) – engines and boilers (pt 088, 090, 001, 011, 095)

Kerr-McGee Gathering, Fort Lupton/Platte Valley/Lancaster (123-0057) – turbine (pt 052) and engines (pt 038 through 044, and 047 through 049)

Metro/Suez Waste Water Cogeneration Facility (001-0097 major for NOx)

MillerCoors Golden Brewery (059-0006) – emission points with emissions equal to or greater than 2 tpy VOC or 5 tpy NOx

MMI/EtOH (059-0828) – emission points with emissions equal to or greater than 2 tpy VOC or 5 tpy NOx

Nutri-Turf (123-0497) – emission points with emissions equal to or greater than 2 tpy VOC or 5 tpy NOx

Owens-Brockway (123-4406) – emission points with emissions equal to or greater than 5 tpy NOx (pt 001-023, 025)

Public Service Company, Cherokee (001-0001) – turbines (pt 028, 029)

Public Service Company, Fort Saint Vrain (123-0023) – turbines (pt 010, 011, 001)

Public Service Company, Denver Steam Plant (031-0041) – boilers (pt 001, 002)

Public Service Company, Zuni (031-0007) – boilers (pt 001, 002, 003)

Public Service Company, Fort Lupton (123-0014) – turbines (pt 001, 002)

Public Service Company, Valmont (013-0001) – turbine (pt 002)

Rocky Mountain Bottle (059-0008) – glass melt furnaces (pt 001)

Suncor (001-0003) – boilers (pt 309, 019, 021, 023)

Tri-State Generation and Transmission, Frank Knutson (001-1349) – turbines (pt 001, 003)

TRNLWB, LLC (Trinity Construction Materials) (059-0409) – shale kiln (pt 001)

University of Colorado (013-0553) – Power House and East District – boilers (pt 001, 002, 012, 013) and Williams Village– boilers (pt 016, 017)

WGR Asset Holding, Wattenberg (001-0025) – boiler (pt 012), turbine and duct burner (pt 021) and engines (pt 004 and 018)

Based on the information provided in these RACT analyses as well as the Division's own in-depth review of rules adopted by Moderate nonattainment areas in other states and EPA guidance such as the RACT/BACT/LAER Clearinghouse, the Commission adopted RACT requirements in Section XVI.D. for stationary combustion equipment located at existing major sources of NO_x in the DMNFR. The requirements of Section XVI.D. only apply to existing stationary combustion equipment located at sources in the DMNFR that were major for NO_x as of June 3, 2016 (i.e. the effective date of the DMNFR's reclassification to Moderate nonattainment).

Definitions

The definition for "stationary combustion equipment" refers to individual emission points and not grouped emission points.

Emission limitations and operational requirements

The Commission adopted categorical emission limitations (Section XVI.D.4.), which vary based on fuel type and size of the stationary combustion equipment, where applicable. Affected stationary combustion equipment is required to comply with these exemptions by October 1, 2021. This compliance period is necessary in order to allow affected sources sufficient time to complete any capital expenditures, install any control or monitoring equipment, and/or satisfy any permitting requirements necessary to comply with the applicable emission limitation. The heat input size threshold for determining whether an emission limitation applies refers to the maximum design value of the stationary combustion equipment. De-rated heat input is not the equivalent of maximum design value heat input. Therefore, stationary combustion equipment cannot simply de-rate to fall below the size threshold. For certain categories of stationary combustion equipment, if the equipment's heat input is below the applicability threshold for the emission limitations, then the equipment would still be required to comply with the combustion process adjustment requirements originally adopted by the Commission during the November 17, 2016 rulemaking (now in Section XVI.D.6.) The compliance date for the categorical emission limits (i.e. XVI.D.4 and XVI.D.5) is independent of the compliance date for the combustion process adjustment (i.e. XVI.D.6(b)(vi)(A)).

The combustion process adjustment requirements shall apply as RACT to a particular piece of equipment in accordance with the applicability provision, Section XVI.D.6.a., regardless of whether or not that piece of equipment is subject to a categorical emission limit in Section XVI.D.4. As described in Section XVI.D.6.a., the combustion process adjustment requirements only apply to stationary combustion equipment with uncontrolled actual emissions of NO_x equal to or greater than 5 tons per year located at major sources of NO_x. For stationary combustion turbines, the heat input capacity threshold for the emission limitations takes into account to the heat input capacity of the stationary combustion turbine only and not the heat input capacity of the stationary combustion turbine and any duct burner that may be used.

For glass melting furnaces at major sources of NO_x, the Commission adopted a production-based categorical emission limitation (Section XVI.D.4.d.). Emissions from some glass melting furnaces are routed through a common stack, where total emissions from multiple furnaces are monitored on a continuous basis. Where this is the case, the total emissions, as monitored from the common stack, shall be divided by the total glass production from all glass melting furnaces associated with the common stack to demonstrate compliance with the categorical RACT limit.

Exemptions

The Commission determined several exemptions from compliance with the categorical RACT standards to be appropriate for Colorado's source mix. In Section XVI.D.2.a., the Commission adopted a 20% capacity factor exemption for boilers and a 10% capacity factor exemption for stationary combustion turbines and compression ignition reciprocating internal combustion engines. The Commission established the 20% and 10% capacity factor exemptions, in part, as a consolidation of a number of limited-use exemptions that were analyzed and considered by the Division to limit the complexity of the categorical rules and adequately accommodate technical and cost concerns for limited-use equipment. A number of stakeholders requested reasonable exemptions for specific equipment types involving seasonal operation, limited-use, natural gas curtailment, emergency electric generation, provision of replacement capacity during periods of extended primary unit outage for major maintenance, and the lack of manufacturer emission rate guarantees for low capacity units. The Commission determined that the capacity factor exemptions addressed each of these concerns, and thus that additional individual exemptions were not necessary beyond the capacity factor exemption.

At low capacities, controls are often cost prohibitive or technologically infeasible. The Commission determined that there are multiple facilities with excess steam capacity that have the ability to shift capacity (and therefore emissions) away from older higher emitting boilers that are not currently configured to comply with the categorical standard or monitoring requirements. Many of the older boilers are not equipped with continuous emission monitoring systems ("CEMS") and may require add-on controls to comply with the categorical standard. The shift in capacity to newer, lower emitting boilers which are already equipped with NO_x controls and CEMS will result in a net emissions reduction. The 20% capacity factor exemption for boilers provides a secondary compliance option and incentive to facilities that have this ability, and the resulting shift in emissions from high emitting units to low emitting units will result in an overall environmental benefit.

Some stakeholders expressed concerns that a few boilers with low historical use (e.g. heat input below 25%) may need to install controls that cannot meet the RACT standard because manufacturer emission rate guarantees usually apply only when the units operate between 25-100% of the boiler maximum continuous rating ("MCR"). Generally, the boiler burners have a limited range of heat input where the manufacturer can guarantee compliance with a specific emission rate. Emissions from boilers operating at heat inputs below 25% MCR are generally classified as startup/shutdown emissions. Thus, if the Division proposed a RACT standard that a particular low utilization boiler was unable to meet and the Division did not offer an adequate capacity factor exemption, the operator would need to install controls and operate the boiler at higher capacity factors to ensure the installed controls meet manufacturer guaranteed emission rates in order to comply with the RACT standard.

The installation of boiler controls coupled with increasing boiler heat input in order to ensure compliance with a categorical RACT standard runs contrary to the original intent of reducing emissions, thus the Commission concludes that it is reasonable to allow exclusion of limited-use boilers from the categorical standard and associated CEMS requirements, particularly regarding boilers with historically low heat inputs that could not rely on the manufacturer emission rate guarantees if the installation of emission controls are needed in order to comply with the categorical standard. Consequently, the Commission determined that a 20% capacity factor averaged over a 3-year period is reasonable for these limited-use boilers.

For stationary combustion turbines and compression ignition RICE, a 10% capacity factor exemption from the proposed categorical emission standards and monitoring requirements is appropriate because combustion turbines and compression ignition RICE are more likely to operate during the summer months. Moreover, for turbines and compression ignition RICE that are used primarily for emergency power generation or peak demand, historic capacity factors are extremely low (0%-5%), and a 10% capacity factor exemption will provide enough operational flexibility to respond to emergency and peak demand events.

Separately, the categorical RACT for glass melting furnaces provides a 35% low usage allowance similar to capacity factor.

The capacity factor is determined based on the rolling 3-year average of the actual heat input for each calendar year divided by maximum allowable heat input. Alternatively, for electric generating units, the proposal allows for capacity factor to be determined based on electric output, which is consistent with the federal Acid Rain Program.

The Commission intended that the exemption for stationary combustion equipment with total uncontrolled actual emissions less than 5 tpy NO_x was based on the permitting threshold in Regulation 3. Similarly, this equipment was not exempted from having to undergo a RACT analysis. The owner or operator must use the most recent air pollution emission notice ("APEN") submitted to the Division to determine total uncontrolled actual emissions.

Stationary combustion equipment that meets one of the exemptions contained in Section XVI.D.2. is not required to comply with the emission limitations, the compliance demonstration requirements and the related recordkeeping and reporting requirements contained in Sections XVI.D.4., XVI.D.5., XVI.D.7., and XVI.D.8., except for XVI.D.7.g, which requires a source that qualifies for an exemption under Section XVI.D.2., to maintain records demonstrating an exemption applies. All stationary combustion equipment is subject to some level of recordkeeping and may also be subject to combustion process adjustment requirements.

Once stationary combustion equipment no longer qualifies for any exemption, the owner or operator must comply with the applicable requirements of Section XVI.D. as expeditiously as practicable but no later than 36 months after the equipment is no longer exempt. Therefore, if any stationary combustion equipment has to undertake a capital expenditure, such as installing a CEMS, in order to comply with Section XVI.D., then they have up to a maximum of three years to come into compliance. However, if no such capital expenditure or change in operational practice is required, then the stationary combustion equipment should comply sooner than three years (i.e. as expeditiously as practicable.) Additionally, once stationary combustion equipment no longer qualifies for any exemption, the owner or operator must conduct a performance test using EPA test methods within 180 days and notify the Division of the results and whether emission controls will be required to comply with the emission limitations. This means that a source can fall into and out of having to comply with the emission limitation, monitoring, recordkeeping and reporting requirements of the rule if they satisfy the performance test requirements (i.e. the Division will not follow a "once in/always in" approach with respect to emission control requirements of exemptions.) Similarly, this 180-day period starts once the equipment is no longer exempt.

Monitoring, recordkeeping and reporting requirements

The Commission determined that affected stationary combustion equipment comply with certain monitoring, recordkeeping and reporting requirements by October 1, 2021. In order to provide clarity and regulatory certainty, many of the monitoring requirements adopted by the Commission incorporate by reference existing federal requirements and are consistent with rules in Moderate nonattainment areas in other states establishing RACT for these source categories.

The Commission is requiring CEMS or continuous emissions rate monitoring systems ("CERMS") for boilers with a maximum design heat input capacity equal to or greater than 100 MMBtu/hr, lightweight aggregate kilns with a maximum heat input design capacity equal to or greater than 50 MMBtu/hr, and glass melting. CERMS may require a stack gas flow rate monitor, where necessary, in order to measure volumetric flow rate and mass emissions. Where stack gas velocity is extremely low, as may be the case for a glass melting furnace, flow can be measured using a Division approved calculation methodology if flow cannot be accurately measured using traditional differential pressure or ultrasonic flow measuring devices. Moreover, where measuring emission rates in terms of emissions per unit of heat input (i.e. lb/MMBtu), EPA Method 19 calculations may be used using the appropriate F factor (i.e. the ratio of combustion gas volumes to heat inputs).

Further, it is the Commission's intent to allow electric utility boilers and stationary combustion turbines subject to the Acid Rain Program to use the quality assurance/quality control and data validation procedures in 40 CFR Part 75 for monitoring emissions to satisfy monitoring, recordkeeping and reporting requirements in this rule. Affected units that are subject to a NO_x emission limitation in an NSPS and use CEMS or CERMS to monitor compliance with that limit can use those monitoring, recordkeeping and reporting requirements to demonstrate compliance with this rule.

Similarly, owners or operators of stationary combustion turbines using performance testing to demonstrate compliance with NO_x emission limitations of NSPS GG or KKKK may utilize those procedures for demonstrating compliance with the emission limitation in this rule. Where an initial performance test has already been conducted to determine compliance with NSPS GG or KKKK, it is not expected that another initial performance test must be performed for purposes of demonstrating compliance with Section XVI.D. Where an initial performance test has not been previously conducted, it must be completed by October 1, 2021 to demonstrate compliance.

For each initial or periodic test, sources should calculate the backup fuel's heat input for the calendar year prior to the year in which the performance test is required to determine if a test is required for each fuel or only for the primary fuel. Moreover, periodic performance tests must be conducted no more than 24 months apart.

With respect to the fuel flowmeter requirements, the Division reserves the right to audit quality assurance procedures with respect to manufacturer's instructions. The heat input measured and recorded by the fuel flowmeter is to be in the same unit of measurement as the applicable emission limitation. With respect to the quarterly or semi-annual reporting requirement, the Commission intended to only require that reports be submitted no less than semi-annually, but a source may submit quarterly reports in order to be consistent with existing reporting frequencies established in a permit and/or applicable NSPS or NESHAP.

With respect to the performance test reports, all performance test reports must compare average emissions determined by the performance test with the applicable emission limitation using the same number of significant figures as the emission limitation.

Incorporation by Reference in Sections XIX. and XVI.

Section 24-4-103(12.5) of the Colorado Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information, making the regulations available and because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. However, these regulations are included in the SIP in order to establish RACT, which must be included in the SIP to satisfy CAA Sections 172(c) and 182(b). Therefore, in order to comply with Part D of the CAA, the Commission has incorporated federal regulations in Sections XVI.D.5. and XIX.A. through D. by reference.

Additional Considerations

Colorado must revise its ozone SIP to address the ozone Moderate nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's Moderate nonattainment area obligations, including those related to RACT. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs; however, in accordance with C.R.S. § 25-7-110.5(5)(b), the Commission nonetheless determines:

- (I) The revisions to Regulation Number 7 address RACT requirements for major sources of VOC and NOx in Colorado's ozone nonattainment area. Colorado's major sources of VOC and NOx are subject to various and numerous NSPS or NESHAP, Regulation Number 7 RACT requirements, or RACT/beyond RACT analyses. The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and NOx in the SIP. Specifically, the Commission adopted RACT requirements in Section XVI.D. for combustion equipment located at major sources of NOx in the DMNFR. MACT DDDDD, MACT JJJJJ, MACT ZZZZ, MACT YYYY, NSPS Db, NSPS GG, NSPS KKKK, NSPS IIII, NSPS JJJJ, NSPS OOOO, NSPS OOOOa, and the compliance demonstration requirements in 40 CFR Parts 60 and 75 may apply to such stationary combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to specific existing stationary combustion equipment in the DMNFR.
- (II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies in order to comply. EPA has provided some flexibility in certain NSPS and MACT. Certain stationary combustion equipment with a lower heat input may trigger the combustion process adjustment work practice requirements of this rule.
- (III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado must adopt applicable provisions into its SIP directly, as the Commission has done here.
- (IV) Colorado will be required to comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.
- (V) EPA has established a January 1, 2017, deadline for this SIP submission. There is no timing issue that might justify changing the time frame for implementation of federal requirements.
- (VI) The revisions to Regulation Number 7, Sections XVI. and XIX. establish categorical RACT for major sources of VOC and/or NOx, and thus are necessary to satisfy RACT SIP requirements for Moderate nonattainment areas and are specific to existing emission points at major sources of VOC and NOx, allowing for continued growth at Colorado's major sources.
- (VII) The Revisions to Regulation Number 7, Sections XVI., and XIX. establish reasonable equity for major sources of VOC and/or NOx by providing the same categorical standards for similarly situated and sized sources.

- (VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018 (Colorado has requested a 1-year clean data extension), EPA will likely reclassify Colorado as a serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs.
- (IX) Where necessary, the revisions to Regulation Number 7 include minimal additional monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.
- (X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. The revisions concerning major sources of VOC and/or NOx generally reflect current emission controls and work practices.
- (XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.
- (XII) Although alternative rules could also provide reductions in ozone and help to attain the NAAQS, the Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an unapprovable SIP and possibly an EPA FIP and/or sanctions.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the Moderate nonattainment area requirements. However, to the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

- (I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.
- (II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of the ozone precursors VOC and NOx.
- (III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.
- (IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.
- (V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

R. November 15, 2018 (Sections I., II., VI., VIII., IX., X., XII., XIII., XVI., XVII., XIX., XX., and XXI.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's ("Commission") Procedural Rules.

Basis

On May 21, 2012, the Denver Metro/North Front Range ("DMNFR") area was designated as marginal nonattainment for the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"), effective July 20, 2012, with an attainment date of July 20, 2015 (77 Fed. Reg. 30088). On May 4, 2016, the U.S. Environmental Protection Agency ("EPA") published a final rule that determined that DMNFR area failed to attain the 2008 8-hour Ozone NAAQS by the applicable marginal attainment deadline and therefore reclassified the DMNFR area to moderate, effective June 3, 2016.

Due to the reclassification, Colorado must submit revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") moderate nonattainment area requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (See 80 Fed. Reg. 12264 (March 6, 2015)). The SIP revision must include Reasonably Available Control Technology ("RACT") requirements for major sources of VOC and/or NO_x (i.e., sources that emit or have the potential to emit 100 tons per year ("tpy") or more) and VOC source categories addressed by an EPA Control Techniques Guideline ("CTG").

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, C.R.S. §§ 25-7-101, et seq., ("Act"), Section 25-7-105(1)(a) directs the Commission to promulgate such rules and regulations necessary for the proper implementation and administration of a comprehensive SIP that will assure attainment and maintenance of national ambient air quality standards. Section 25-7-301 directs the Commission to develop a program providing for the attainment and maintenance of each national ambient air quality standard in each nonattainment area of the state. Section 25-7-106 provides the Commission flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106(1)(c) and (2) also authorize the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution, and monitoring and recordkeeping requirements. Section 109(1)(a) authorizes the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources of air pollutants.

Purpose

In November 2016, the Commission determined that some major sources and CTG VOC source categories were adequately addressed under existing SIP requirements. The Commission also adopted new requirements for some major sources and CTG VOC source categories. In November 2017, the Commission adopted categorical RACT requirements for the oil and gas industry in response to EPA's Oil and Gas CTG. In July 2018, the Commission adopted categorical RACT requirements for combustion equipment at major sources that the Commission determined in 2016 were not addressed by SIP RACT requirements.

In this rulemaking, the Commission adopts SIP requirements that further support and complete Colorado's obligation as a moderate ozone nonattainment area to revise Colorado's SIP to include provisions that implement RACT for all major sources of VOC and/or NOx and for all CTG VOC source categories in the DMNFR ozone nonattainment area. Specifically, the Commission adopts categorical RACT requirements for major source breweries, wood furniture manufacturing, and addresses EPA concerns with the industrial cleaning solvent, metal furniture surface coating, and miscellaneous metal surface coating requirements. The Commission also revises specific rule or reference methods incorporated by reference to add applicable citation dates. Last, the Commission adopts specific revisions in a SIP clean-up effort.

Further, the Commission corrects typographical, grammatical, and formatting errors found throughout Regulation Number 7.

Major source RACT

Colorado has major sources of VOC and/or NOx in the DMNFR. Under marginal and moderate ozone nonattainment classifications, major sources are sources with the potential to emit greater than or equal to 100 tpy of NOx or VOC. Many of the major sources analyzed in 2016 were already subject to regulatory RACT requirements in Colorado's SIP, individual RACT requirements established in federally enforceable permits as a minor source RACT requirements, or an applicable federal New Source Performance Standard ("NSPS") or National Emission Standard for Hazardous Air Pollutant ("NESHAP"). However, as a moderate nonattainment area, Colorado must include provisions in the SIP to implement RACT for Colorado's major sources. In November 2016, the Commission directed some major sources to submit RACT analyses to the Division, including two major source breweries. The Commission adopts in this November 2018, rulemaking categorical RACT requirements for major source brewing activities.

Major source breweries

The Commission adopts RACT requirements for owners and operators of breweries producing malt beverages and their brewery related operations at a major source VOC as of June 3, 2016, located in the DMNFR. In a moderate ozone nonattainment area, a major VOC source is one that emits or has the potential to emit greater than 100 tpy VOC. A brewery includes brewhouse, fermentation, aging, and/or packaging operations. Brewery related operations include operations that support the production of malt beverages such as wastewater management, container manufacturing, and ethanol distillation. The Commission established RACT for combustion equipment, including at breweries, in July 2018, in Regulation Number 7, Section XVI. The Commission now adopts a process loss limit and pollution prevention requirements for brewery packaging operations. These pollution prevention provisions include performance metrics to reduce product loss, operator training, and packaging equipment to reduce container breakage and product loss. The Commission also adopts wastewater management and treatment requirements for land application of wastewater. Lastly, the Commission adopts requirements for owners or operators to keep records of production, pollution prevention activities, and wastewater to demonstrate compliance with the operational requirements.

The largest VOC emissions sources inside a brewery are associated with packaging operations, including can, bottle, and other container fillers. Breweries can reduce VOC emissions by optimizing packaging operations. The process loss limitation is representative of packaging and filling optimization and, therefore, is an indicator, and potential driver, of the resulting VOC emission reductions. The process loss limitation does not include the railcar loading of beer concentrate that is shipped off-site for packaging. In this process, empty railcars are filled with beer concentrate held in beer concentrate receiving tanks after the aging process. The process loss from the automated loading of the beer concentrate from tanks into railcars is minimal and emissions from the filling of cans, bottles, kegs, or other containers are included with the emissions of the off-site packaging facility.

The process loss is calculated on calendar month and rolling 12-month bases across all packaging operations (i.e., filling lines), which aligns with existing product tracking programs. Process loss equates to the difference in the quantity of malt beverage metered at the filler and the quantity in containers as tracked for the Alcohol and Tobacco Tax and Trade Bureau ("TTB"). Operators determine the average calendar month process loss by comparing the total volumes metered at the fillers to the total volume counted by the TTB case counters. Owners or operators will then determine monthly average process loss percentage by dividing the difference in meter and case counter values by the total volume metered at the fillers. Utilizing an average process loss limit also allows for variations in individual line or brand product loss due to specialty brands or innovative containers. The brewing industry is seeing decreased sales of high-volume brands and increased consumer demand for small-volume unique or complex brands. This market change impacts process loss as the high-volume brands have low process loss values whereas specialty brands often result in higher process loss values due to brand recipe complexity, brand mix complexity, and production schedule complexity. The packaging of more types of brands and more complex brands result in higher process loss values because of differences in recipes that require more time for the filler to adjust to the appropriate fill level, more frequent product changeovers of the filling lines, and more unique packaging. The requirement to completely flush a filling line between brands also increases process loss values when the specialty brands are produced in lesser quantities than high-volume brands. Further, bottle filling lines often have different process loss values than can filling lines, therefore the change in container demand can impact the overall process loss. The average process loss limit of 6 percent on a calendar month and 4 percent on a 12-month rolling average leaves the necessary margin for variability and innovation, while still providing an indicator of RACT-level control of brewery packaging operations VOC emissions.

The Commission exempts from the process loss, pollution prevention, and recordkeeping requirements emissions units' subject to a work practice or emission control requirement in another federally enforceable section of Regulation Number 7 and emission units with total uncontrolled actual VOC emissions less than two tons per year. The first exemption was adopted to avoid subjecting sources to overlapping, duplicative, or contradictory RACT requirements. The second exemption was adopted for consistency with other major source RACT provisions and the use of Colorado's permitting thresholds for NOx and VOC to identify the emission points at major sources for which Colorado evaluated RACT.

The Commission also exempts equipment or activities related to research and development and newly installed, upgraded, or replaced packaging operations. Research and development activities include testing different recipes and packaging types before a product is distributed into commerce. The six-month startup exemption for newly installed, upgraded, or replaced packaging operations allows for the testing and adjustment of the new equipment to meet performance requirements. Examples of newly installed, upgraded, or replaced packaging operations include a new filling line or an upgraded or replaced man-to-machine-interface. Startup of newly installed, upgraded, or replaced packing operations does not include the startup or changeover of malt beverages or new recipes. Quality assurance teams follow a statistical process to verify that equipment is meeting quality standards prior to releasing salable product. These processes may include additional container testing, product sampling, or additional filler flushes while packaging operations are fine-tuned to meet key performance indicators. The volume of the product metered at the filler during the research and development and startup processes is excluded from the monthly process loss calculations. However, new, upgraded, or replaced packaging operations are not exempt from employees training requirements to ensure that employees understand the new packaging operations after startup.

Pollution prevention provisions also include the use and operation of packaging equipment to reduce container breakage and product loss. The Commission exempts from the automated filling equipment requirements packaging operations at pilot brewery operations. Automated filling equipment may be mechanical with a set fill quantity or electric with a flow meter and adjusting fill quantity. Both processes improve consistency, reduce spillage and product loss, and reduce the variation that may occur from human error.

The automated filling lines also include fill level detectors that will reject inadequately filled containers for recovery and recycling. A pilot brewery operation may serve the purposes of research and development but can also be utilized to produce very small quantities of product that is distributed into commerce. Pilot brewery operations can include different filling operations (e.g., bottles, kegs) but may use some manual filling related processes instead of automated processes. The use of manual processes is consistent with industry practices for operations of this small size, less than 50,000 barrels per year, and provides flexibility to account for production variations that may occur during research and development or small batch production.

Wood furniture manufacturing

In 2016, the Commission determined that only one source in the DMNFR exceeded the Wood Furniture CTG applicability threshold, and that source was a major source of VOC. Therefore, the Commission incorporated by reference requirements in 40 CFR Part 63, Subpart JJ (National Emission Standards for Wood Furniture Manufacturing Operations) into the SIP for wood furniture surface coating operations. In the 2008 Ozone NAAQS Implementation rule, EPA stated that states could streamline their RACT analysis by relating MACT controls to VOC RACT considerations. However, EPA has since expressed concerns that the NESHAP JJ volatile hazardous air pollutant ("VHAP") coating content limits may not adequately address coating VOC emissions. The Commission therefore removes the incorporation by reference of NESHAP JJ for wood furniture manufacturing operations in Section XIX. and is instead including the CTG recommended coating VOC content limits and work practices in Section IX.O.

The coating VOC content limits apply to sealers, topcoats, acid-cured alkyd amino vinyl sealers, or acid-cured alkyd amino conversion varnish topcoats. EPA's Wood Furniture CTG does not define acid-cured topcoats or sealers but does describe acid-catalyzed finishes as the most common catalyzed finishes. The Wood Furniture CTG further states that the film-forming resins in these finishes are usually a urea-formaldehyde or melamine-formaldehyde prepolymer mixed with an alkyd resin that serves as a plasticizer. Common catalysts contained in the acid-catalyzed finishes include sulfuric acid and p-toluenesulfonic acid and film formation occurs through curing (polymerization) of the resins rather than drying.

SIP Clean-up

Industrial Cleaning Solvent

In 2016, the Commission adopted provisions in Regulation Number 7, Section X. to include RACT requirements related to the use of industrial cleaning solvents. The Commission adopted several exemptions recommended by EPA's Industrial Cleaning Solvents CTG as well as exemption for sources complying with cleaning solvent requirements in a federally enforceable NSPS, NESHAP, Best Available Control Technology requirement, or Lowest Achievable Emissions Rate requirement, which was similar to an EPA approved exemption in Colorado's Regional Haze SIP. EPA has since indicated concerns with approving this broad exemption due to a perceived lack of specificity. The Commission therefore removes the broad exemption in Section X.E.4.a.(i).

Metal furniture and miscellaneous metal surface coating

EPA published Metal Furniture CTGs in 1977 and 2007 and Miscellaneous Metal Parts and Products CTGs in 1978 and in 2008. In the 2008 Ozone NAAQS Implementation rule, EPA stated that states could conclude that sources already addressed by RACT determinations for a previous ozone NAAQS do not need to implement additional controls because a new RACT determination would result in the same or similar control technology as the initial RACT determination and any incremental emissions reduction from the application of a second round of controls would be small and the cost unreasonable.

Therefore, in 2016 the Commission relied on the RACT provisions relating to the 1977 and 1978 CTGs adopted into Regulation Number 7, Sections IX.H. and IX.L. in 1978 and 1980 to continue to establish RACT for metal furniture and miscellaneous metal coating operations. EPA has since indicated concerns with the existing provisions due to a lack of specified application technique. The Commission therefore revises Section IX. to specify the use of good air pollution control practices, including efficient application methods.

1990 and 1991 RACT Reports

In 1990, the Commission adopted one of several requirements in Regulation Number 7, specifically Sections I.B.2.f. and I.B.2.g., for existing sources to address EPA concerns with the design, implementation, and enforceability of Colorado's previously submitted and approved Ozone SIP. The provisions included one-time reporting requirements concerning source emissions and RACT for sources existing as of 1989. The provisions were not an ongoing reporting requirement potentially necessary for monitoring compliance with applicable emissions limits. EPA approved these provisions into Colorado's SIP in 1995, without discussion. Due to these one-time requirements having passed and Colorado's major stationary sources being subject to RACT requirements in Regulation Number 7, as adopted by the Commission through 2018, the Commission removed these historic provisions. Removal of these provisions does not remove or modify any control measures, therefore does not affect emissions nor interfere with attainment or reasonable further progress. Where information in the Sections I.B.2.f. and I.B.2.g. reports informed RACT requirements under Section II.C., sources remain subject to applicable RACT requirements and any emission reporting requirements as addressed by the emission statement rule last approved by EPA in 2015 (See 80 Fed. Reg. 50205 (August 19, 2015)).

Incorporation by Reference

Section 24-4-103(12.5) of the Colorado Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission included reference dates to rules and reference methods incorporated in Regulation Number 7, Sections II., VI., VIII., IX., X., XII., XIII., XVI., and XVII.

Additional Considerations

Colorado must revise its Ozone SIP to address the moderate ozone nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the 8-hour ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to ensure attainment with the 2008 8-hour ozone NAAQS and satisfy Colorado's moderate nonattainment area obligations, including those related to RACT. These revisions do not exceed or differ from the federal act due to state flexibility in developing nonattainment area SIPs; however, in accordance with C.R.S. § 25-7-110.5(5)(b), the Commission nonetheless determines:

- (I) The revisions to Regulation Number 7 address RACT requirements for major sources of VOC in Colorado's ozone nonattainment area. Colorado's major sources of VOC are subject to various and numerous NSPS or NESHAP, Regulation Number 7 requirements, or RACT/beyond RACT analyses. The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC in the SIP. Specifically, the Commission adopted RACT requirements in Section XX. for brewing activities located at major sources of VOC in the DMNFR. The Commission also adopted RACT requirements from EPA's Wood Furniture CTG for wood furniture surface coating in Section IX. MACT JJ may apply to wood furniture surface coating operations.

- (II) The federal rule discussed in (I) is primarily technology-based in that it largely prescribes the use of specific coating VHAP contents in order to comply. The federal rule provides flexibility by allowing subject facilities to select any coating meeting the specified VHAP content limits.
- (III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's moderate nonattainment area RACT obligations. Instead, Colorado must adopt applicable provisions into its SIP directly, as the Commission has done here.
- (IV) Colorado will be required to comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.
- (V) EPA has established a January 1, 2017, deadline for this SIP. There is no timing issue that might justify changing this time frame.
- (VI) The revisions to Regulation Number 7, Sections IX., X., and XX. establish categorical RACT for major sources of VOC and CTG VOC source categories, and thus are necessary to satisfy RACT SIP requirements for moderate nonattainment areas. The provisions are specific to emission points at sources of VOC, allowing for continued growth at Colorado's sources.
- (VII) The Revisions to Regulation Number 7, Sections IX., X., and XX. establish reasonable equity for sources of VOC by providing the same categorical standards for similarly situated and sized sources.
- (VIII) If Colorado does not attain the 2008 ozone NAAQS by July 20, 2018 (Colorado has requested a one-year clean data extension) EPA will likely reclassify Colorado as a serious ozone nonattainment area, which automatically reduces the major source thresholds from 100 tons per year of VOC and NOx to 50 tons per year; thus subjecting more sources to major source requirements. If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. Either of these outcomes may subject others to increased costs.
- (IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.
- (X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. The revisions concerning major sources of VOC generally reflect current emission controls and work practices.
- (XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 contribute to the prevention of ozone in a cost-effective manner.
- (XII) Although alternative rules could also provide reductions in ozone and help to attain the NAAQS, the Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an unapprovable SIP and possibly an EPA FIP and/or sanctions.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in C.R.S. § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the moderate nonattainment area requirements. However, to the extent that C.R.S. § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

- (I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.
- (II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of the ozone precursors VOC and NOx.
- (III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.
- (IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.
- (V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

S. December 19, 2019 (Sections I. through XX. and Appendices A through F – reorganized into Parts A through F)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act Sections 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, Colorado Revised Statutes (CRS) Sections 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's (Commission) Procedural Rules.

Basis

During the 2019 legislative session, Colorado's General Assembly adopted revisions to several Colorado Revised Statutes in Senate Bill 19-181 (SB 19-181) (Concerning additional public welfare protections regarding the conduct of oil and gas operations) that include directives for both the Oil and Gas Conservation Commission and the Air Quality Control Commission (Commission). This proposed rulemaking focuses on the Air Quality Control Commission directives in Section 25-7-109, CRS, SB19-181 directs the Commission to adopt regulations to "minimize emissions of methane and other hydrocarbons, volatile organic compounds (VOC), and oxides of nitrogen (NOx)" from all the "natural gas supply chain." Further, SB 19-181 identifies specific provisions the Commission should consider including semi-annual leak detection and repair (LDAR) inspection requirements at all well production facilities, transmission pipeline and compressor station inspection requirements, continuous methane emission monitoring requirements, and pneumatic device requirements. This rulemaking addressed many of the specific provisions for consideration, except continuous methane monitoring, but is only the first of many rulemakings to come in addressing SB 19-181.

Further, on August 15, 2019, the Environmental Protection Agency (EPA) proposed to reclassify the Denver Metro North Front Range (DMNFR) to Serious, after 2015-2017 ozone data failed to show attainment of the 2008 8-hour Ozone National Ambient Air Quality Standard (NAAQS) of 75 parts per billion (ppb). See 84 Fed. Reg. 41,674 (Aug. 15, 2019). As a Serious area, the major source threshold lowers from 100 tons per year (tpy) of VOC or NOx to 50 tpy and the DMNFR's attainment date becomes July 20, 2021. EPA has also designated the DMNFR as Marginal nonattainment for the 2015 ozone NAAQS of 70 ppb, with an attainment date of August 3, 2021.

Therefore, as a first step to addressing the new statutory directives, and ensuring progress towards attainment of the 2008 and 2015 ozone NAAQS, the Commission is adopting revisions to Regulation Number 7 to minimize emissions from the oil and gas sector and to include reasonably available control technology (RACT) requirements for major sources with VOC and/or NOx emissions equal to or greater than 50 tpy. The oil and gas industry is a significant source of VOC, NOx, ethane, and methane emissions, and the Commission expects the industry's growth to continue in the foreseeable future. Improved technologies and business practices, many already utilized by Colorado oil and gas operators, can reduce emissions of hydrocarbons such as VOCs, ethane, and methane in a cost-effective manner. These technologies and practices include, without limitation, frequent LDAR inspections, reducing emissions from pneumatic controllers, reducing emissions from the transmission segment, storage tank measurement systems, and vapor collection and return equipment.

For these reasons and more, the Commission believes additional control measures beyond the current requirements in Regulation Number 7 and NSPS OOOO (and NSPS OOOOa) are appropriate. Colorado's considerable experience with the regulation of oil and gas sources involves both State Implementation Plan (SIP) requirements that apply in the DMNFR and state-only requirements that apply state-wide. In addition, evidence in the rulemaking record supports the conclusion that the rules can be implemented effectively. Accordingly, the Commission concludes that the rules are technologically feasible and cost-effective.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Sections 25-7-101, CRS, *et seq.* (Act), specifically § 25-7-105(1), directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in Section 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere (and, as such, includes VOC, NOx, methane and other hydrocarbons) and provides the Commission broad authority to regulate air pollutants.

Section 105(1)(a)(I) directs the Commission to adopt a state implementation plan (SIP) to attain the NAAQS. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Sections 25-7-109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons. Section 25-7-109(10) directs the Commission to adopt emission control regulations to minimize emissions of methane, other hydrocarbons, VOC, and NOx from oil and gas operations.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 7, and includes technological and scientific rationale for the adoption of the revisions. The Commission adopts revisions to Regulation Number 7 to address hydrocarbon emissions from oil and gas operations, including well production facilities and natural gas compressor stations. The Commission expands the inspection and enhanced response program for pneumatic controllers it adopted in 2017 for pneumatic controllers in the DMNFR to a state-wide applicability. The Commission adopts a new, innovative performance based program to reduce emissions from the downstream transmission segment.

The Commission is replacing the system-wide condensate storage tank control strategy in the SIP with a more straight-forward storage tank control threshold. The Commission is also seeking to reduce emissions from storage tank measurement and sampling and loadout activities, and to minimize fugitive emissions from leaking components at natural gas compressor stations and well production facilities. Further, the Commission is expanding the requirement to employ best management practices to minimize emissions at oil and gas wells during well plugging activities. The Commission is also establishing an annual emissions inventory report that oil and gas operators will submit to the Division, which will ensure accountability and assist the Commission in understanding the emissions of methane, ethane, VOC, CO, and NOx associated with different activities and equipment in oil and gas operations. The Commission believes that this combination of revisions is appropriate as a first step in minimizing emissions from oil and gas operations and continuing to make progress towards attainment of the ozone NAAQS.

The Commission is revising Regulation Number 7 to include provisions in the SIP that require the implementation of RACT for major sources (≥ 50 tpy NOx and/or VOC) including expanding existing requirements, incorporating federal requirements, including categorical RACT requirements, and requiring the submission of RACT analyses.

The Commission is also updating requirements for gasoline transport trucks, bulk terminals, and service stations to align with current federal requirements in a SIP clean-up effort.

The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

The following explanations provide further insight into the Commission's intention for certain revisions and, where appropriate, the technological or scientific rationale for the revision.

Reorganization

Over the years, Regulation Number 7 has grown. In an effort to facilitate readability, and to better allow the regulated community to identify and understand the provisions governing their activities, the Division is proposing a full reorganization of Regulation Number 7 into parts. A table identifying the new section(s) along with the prior section/location is below. This Statement of Basis and Purpose will refer to the reorganized section numbers in the discussion of revisions and new provisions.

Reorganized Regulation Number 7 Section	Regulation Number 7 Section (as of 11/15/2018)
Part A	
Part A, Section I.	I. Applicability
Part A, Section II.	II. General Provisions
Part A, Appendix A	Appendix A. Colorado Ozone Nonattainment or Attainment Maintenance Areas

Part B	
Part B, Section I.	III. General Requirements for Storage and Transfer of Volatile Organic Compounds
Part B, Section II.	IV. Storage of Highly Volatile Organic Compounds
Part B, Section III.	V. Disposal of Volatile Organic Compounds
Part B, Section IV.	VI. Storage and Transfer of Petroleum Liquids
Part B, Section V.	VII. Crude Oil
Part B, Section VI.	VIII. Petroleum Processing and Refining
Part B, Section VII.	XV. Control of Volatile Organic Compound Leaks from Vapor Collection Systems and Vapor Control Systems Located at Gasoline Terminals, Gasoline Bulk Plants, and Gasoline Dispensing Facilities
Part B, Appendix B	Appendix B. Criteria for Control of Vapors from Gasoline Transfer to Storage Tanks
Part B, Appendix C	Appendix C. Criteria for Control of Vapors from Gasoline Transfer at Bulk Plants (Vapor Balance System)
	Appendix E – deleted, paragraphs B and E moved into section, and references replaced with EPA Method 27

Part C	
Part C, Section I.	IX. Surface Coating Operations
Part C, Section II.	X. Use of Cleaning Solvents
Part C, Section III.	XI. Use of Cutback Asphalt
Part C, Section IV.	XIII. Graphic Arts and Printing
Part C, Section V.	XIV. Pharmaceutical Synthesis
Part C, Appendix D	Appendix D. Minimum Cooling Capacities for Refrigerated Freeboard Chillers on Vapor Degreasers
Part C, Appendix E	Appendix F. Emission Limit Conversion Procedure

Part D	
Part D, Section I.	XII. Volatile Organic Compound Emissions from Oil and Gas Operations
Part D, Section II.	XVII. (State Only, except Section XVII.E.3.a., which was submitted as part of the Regional Haze SIP) Statewide Controls for Oil and Gas Operations and Natural Gas-Fired Reciprocating Internal Combustion Engines
Part D, Section III.	XVIII. (State Only) Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations
Part D, Section IV. (State Only) Control of emissions from the transmission and storage segment	NEW
Part D, Section V. (State Only) Oil and Natural Gas Operations Emissions Inventory	NEW

Part E	
Part E, Section I.	XVI.A.-C. (natural gas fired reciprocating internal combustion engines in the 8-hour ozone control area) and XVII.E. (new, modified, existing, and relocated natural gas fired reciprocating internal combustion engines)
Part E, Section II.	XVI.D. Control of Emissions from Stationary and Portable Combustion Equipment in the 8-Hour Ozone Control Area
Part E, Section III.	XIX. Control of Emissions from Specific Major Sources of VOC and/or NOx in the 8-Hour Ozone Control Area
Part E, Section IV.	XX. Control of Emissions from Breweries in the 8-Hour Ozone Control Area

Part F	
	XXI. Statements of Basis, Specific Statutory Authority and Purpose

State Implementation Plan Revisions (Part D, Section I. (formerly Section XII.))

The Commission adopted several revisions to the SIP provisions that were previously found in Section XII. While not strictly necessary to comply with a particular CAA requirement pertaining to ozone, the revisions implement the mandate of SB 19-181, strengthen Colorado's Ozone SIP, and will achieve further reductions in ozone precursors and other hydrocarbons.

Applicability (Section I.A)

The Commission revised the applicability language of Part D, Section I. to clarify that all oil and gas operations at and upstream of the natural gas processing plant are subject to the provisions of Section I., as more specifically set forth in Sections I.A through L. The Commission also revised the applicability to ensure that storage tanks containing hydrocarbon liquids (e.g., condensate, crude oil) and produced water are subject to the provisions of Section I., which previously applied only to condensate storage tanks.

Further, under previous provisions, owners and operators of condensate storage tanks for which the APENs reflecting emissions from all operations were 30 tpy VOC or less were exempted from Section I. Given the challenges with attaining the ozone NAAQS, the number of tanks that were exempt under this provision, and the need for further reducing emissions from those tanks, the Commission removed this exemption.

However, the Commission retained the exemption from the system-wide control strategy in Section I.I. (formerly Section XII.I.) for owners or operators of natural gas compressor stations that do not also own or operator exploration and production facilities and the exemption in Section I.G. (formerly XII.G.) for owners or operators of natural gas processing plants. Owners or operators of these facilities must continue to control condensate storage tanks as specified in Sections I.I. and I.G. By retaining these exemptions, the Commission does not intend to exempt these facilities from any applicable requirements in Part D, Section II.

Storage Tank Controls (Section I.D)

In 2004, the Commission adopted the initial system-wide control strategy, which required operators to reduce emissions from their system of condensate tanks. The “system” was comprised of condensate tanks with uncontrolled actual VOC emissions equal to or greater than 2 tpy, and allowed operators to decide which tanks to control so long as emissions from the “system” were reduced by specified percentages. The system-wide control strategy involved complicated and often times confusing recordkeeping and reporting. Further, the system-wide control strategy had the unintended impact of disincentivizing operators to build new facilities without storage tanks (a real emissions benefit), because operators could not take credit for the production at tankless facilities in their “system.” As a result, the Commission replaced the system-wide control strategy with a straightforward control threshold. Operators in the 8-hour Ozone Control Area will have until May 1, 2020, (prior to summer ozone season 2020) to install controls on storage tanks with uncontrolled actual VOC emissions equal to or greater than 2 tpy. Only the requirements for storage tanks with uncontrolled actual VOC emissions equal to or greater than 4 tpy are included in the SIP, while the requirements for the storage tanks between 2 and 4 tpy will remain state-only. This provision expands the control requirements to crude oil and produced water tanks, and will result in several hundred more tanks being controlled. The Commission has reviewed the evidence and has determined that the 4 tpy SIP threshold and implementation timetable is cost-effective, technically feasible, and will ensure no backsliding as provided for in the Clean Air Act, Section 110(l). In Sections I.D.3.b.(v) and I.D.3.b.(vi), the Commission has required that storage tanks below the 2 tpy threshold that increase emissions above the threshold must be in compliance with 60 days of the first date of the month after which the threshold was exceeded. As a result, if a storage tank exceeds the 2 tpy threshold in September 2020, based on a rolling twelve-month total (i.e., October 2019-September 2020), the tank must have controls installed and operating within 60 days of October 1, 2020. These provisions will not only minimize emissions from storage tanks but will ensure clarity in the applicability of control requirements and will assist Colorado in making additional progress towards attainment of the ozone NAAQS.

The Commission has also determined that storage tanks that cannot install controls by the applicable compliance date may shut-in all wells producing to the applicable storage tanks, so long as production from any well producing into the storage tank is not resumed until controls are installed. It is the Commission's intent that this allowance not apply unless the operator shuts in all wells feeding in to the storage tank/battery requiring controls. This will avoid the need for operators to install control equipment when wells are shut-in and where the operator may determine not to return those wells to production. Further, the Commission intends that the Division will work with operators in the DMNFR to allow for appropriate time to conduct design analyses to comply with Sections I.C.1.b. and II.C.2.a., as long as operators install required controls by May 1, 2020, and are pursuing compliance with reasonable diligence.

The Commission has also included in the SIP in Sections I.D.2.a. and II.C.1.b.(ii) the existing requirements (formerly Sections XII.D.1. and XVII.C.1.c.) that operators of newly constructed tanks employ controls during the first 90 days after the date of first production (this provision was previously designated state-only). However, these revisions to Regulation Number 7, in conjunction with revisions to Regulation Number 3, use the term "commencement of operation" instead of "date of first production." This SIP revision is not part of Colorado's ozone attainment requirements but is directed at making this requirement enforceable by the EPA and members of the public under the CAA. While the Commission does not believe inclusion of this provision in the SIP was required for compliance with Colorado's permitting program in Regulation Number 3 with CAA requirements, including ozone nonattainment area requirements, pursuant to Section 25-7-105.1(1), CRS, including this provision in the SIP will avoid confusion as to whether compliance with this requirement can be considered a limitation upon a source's potential to emit for purpose of permitting.

Storage Tank Monitoring (Section I.E)

The Commission revised Section I.E. to apply the monitoring requirements to all storage tanks controlled pursuant to Section I.D., which will ensure monitoring not only of condensate tanks, but also of crude oil and produced water tanks on a weekly basis. The required inspections have also been updated to include common-sense elements that can have a real impact on performance of well production facility equipment and can reduce emissions. For example, checking that burner trays are not visibly clogged can improve the performance of air pollution control equipment. The Commission does not intend that operators should shut-in the combustor for the sole purpose of performing this inspection to observe the burner tray, and need only inspect those portions of burner trays that are visible without shutting in. The Commission also adopted into Section I.E. requirements that previously existed in Section II. (formerly Section XVII.) to check that pressure relief valves are properly seated and that vent lines are closed. Similarly, to the inspection in Section II.C.1.d.(i), operators are not expected to disassemble or otherwise manipulate the pressure relief valve to complete the inspection, unless the visual observation of the valve reveals it is unseated and corrective action needs to be taken. Further, the Commission does not expect operators to climb on top of a tank to observe the pressure relief valve. However, operators are expected to use an available catwalk or similar permanent access to ensure the best opportunity for inspection, except when a catwalk is not accessible due to a safety hazard.

The Commission has removed references to recordkeeping from Section I.E. and has attempted to condense all recordkeeping requirements in Section I.F. For example, Section I.E.2.c.(iv) no longer provides that operators must "check for and document" the inspection; instead, Section I.E.2.c. requires operators to "check", and the requirement to "document" the inspection is found in Section I.F.2.c.

Recordkeeping and Reporting (Section I.F)

As a result of replacing the system-wide control strategy with the fixed control threshold, the Commission revised the recordkeeping and reporting requirements for demonstrating compliance with Section I.D. Operators subject to the system-wide control strategy will still be required to submit an annual report for calendar year 2019 by the same deadline of April 30, 2020, and are given until August 31, 2020, to submit the report for the time period in 2020 during which the system-wide control strategy remains effective (*i.e.* January 1 – April 30, 2020). In Sections I.F.2. and I.F.3., the Commission has created a new recordkeeping and reporting scheme for the tanks subject to the new control threshold provisions. The Commission has largely maintained the same recordkeeping and reporting requirements for the monitoring provisions in Section I.E. However, the Commission streamlined the new storage tank recordkeeping and reporting requirements, which are included in the SIP for storage tanks at or above the 4 tpy threshold, but are included on a state-only basis for the storage tanks between 2 and 4 tpy.

Miscellaneous

The Commission adopted revisions to definitions (Section I.B.) and the general provisions (Section I.C.). A new definition for “commencement of operation” was added for consistency with Regulation Number 3 and for clarity as to the applicability of other control requirements (previous versions of Regulation Number 7 were tied to the “date of first production,” which was not implemented consistently amongst operators). The Commission adopted the term “date of first production” in 2014 with the intent that it coincides with the date reported to the Colorado Oil and Gas Conservation Commission (COGCC) on COGCC Form 5A. Through implementation of the 2014 revisions, differences between the Commission’s and the COGCC’s use of the term were realized. Therefore, the Commission has replaced “date of first production” with the more clearly defined “commencement of operation” term.

The Commission also adopted new definitions for “hydrocarbon liquid,” “produced water,” “storage tank,” and “storage vessel” to ensure consistency with the state-only program in Part D, Section II. The definition of “storage tank” referred to the federal definition of “storage vessel” and, therefore, captured crude oil and produced water tanks, in addition to condensate tanks. The federal definition has now been included as a standalone definition of “storage vessel.”

The Commission also revised Section I.C.1.b. to reflect that Section I. now applies to oil and gas operations collecting, storing, processing, and handling hydrocarbon liquids and produced water, not just condensate. The Commission replaced the term “leakage” with the term “emission” in order to be consistent with the Common Provisions definition of “emission.” The Commission does not intend this latter revision to reflect a change in the meaning or applicability of Section I.C.1.b. (or Section II.B.1.a., where this revision is also made), but only to improve clarity.

The Commission revised Section I.C.2., which specifies how operators must calculate emissions and emission reductions for purposes of demonstrating compliance with the control requirements. These revisions expand the current provisions to storage tanks storing hydrocarbon liquids other than condensate and to storage tanks storing produced water. For crude oil tanks and produced water tanks, operators will need to refer to default emission factors as established and updated by the Division. See, *e.g.* PS Memo 14-03, *Oil & Gas Industry Crude Oil, Condensate and Produced Water Atmospheric Condensate Storage Tanks, Regulatory Definitions and Permitting Guidance for General Permit GP08*.

The Commission has not substantively revised the LDAR SIP provisions of Section I.L. but clarified that applicability is based on emissions on a rolling twelve-month basis, not a calendar year basis. Such was the Commission’s intention in adopting the program in 2017.

The Commission has also determined to incorporate Section II.F. (formerly Section XVII.G.) into the SIP. This provision requires control of emissions coming off a separator after a well is newly constructed, hydraulically fractured, or recompleted. These emissions must be routed to a gas gathering line or controlled by air pollution control equipment. This SIP revision is not part of Colorado's ozone attainment compliance requirements, but is directed at clarifying that this requirement is enforceable by the EPA and members of the public under the CAA. Including this provision in the SIP will avoid confusion as to whether compliance with this requirement can be considered a limitation upon a source's potential to emit for purposes of permitting. See Section 25-7-105.1(1), CRS.

State-wide, State-Only Revisions (Part D, Section II. (formerly Section XVII.))

In Part D, Section II., the Commission adopted several revisions to begin its implementation of SB 19-181. These revisions further support existing control requirements and also seek reductions from previously unregulated emissions activities (e.g., gauging and loadout).

Storage Tank Controls, Monitoring, Recordkeeping, and Reporting (Sections II.C.1.c., II.C.1.d., II.C.2.b. and II.C.3.)

Since 2011, Colorado has made significant progress in reducing emissions from storage tanks. However, storage tanks remain the largest source not only of oil and gas VOC emissions, but of all anthropogenic VOC emission sources in the state (per the 2017 nonattainment area emissions inventory in the Moderate area ozone nonattainment SIP). The Commission has determined that it is cost effective and technically feasible to lower the control threshold from 6 tpy VOC (as established in 2014) to 2 tpy VOC. However, the Commission does not want to facilitate or encourage the use of supplemental fuel to operate control equipment, and understands that this can occasionally be an issue on the West Slope, in particular, where the facilities have lower pressure. The Commission has therefore adopted a provision that allows operators to seek from the Division an exception to controlling tanks between 2 and 6 tpy VOC under these circumstances. Exceptions should be sought prior to compliance deadlines, and will be effective upon submittal unless and until the Division determines an exception is not appropriate. Storage tanks constructed on or after March 1, 2020, must have controls upon commencement of operation, ensuring reductions during the 2020 summer ozone season. Storage tanks outside the nonattainment area constructed prior to March 1, 2020, must be in compliance by May 1, 2021. The Commission determined it was appropriate to give tanks outside the nonattainment area between 2 and 6 tpy VOC extra time to install controls. The Commission does not intend to give extra time to storage tanks with air pollution control equipment already installed, even where controls are not currently required by Regulation Number 7 (e.g., where an operator has submitted an APEN claiming controls).

The Commission revised the approved instrument monitoring method (AIMM) schedule for inspections of controlled storage tanks to align with the Commission's revision of the LDAR inspection frequencies in response to SB 19-181, discussed further below. The Commission adopted a semi-annual frequency for storage tanks with emissions greater than or equal to 2 tpy and less than or equal to 12 tpy. For storage tanks with emissions greater than or equal to 6 tpy and less than or equal to 12 tpy, this is an increase in inspection frequency from annual to semi-annual. Where the Commission specifies that semi-annual monitoring must "begin" in a certain year, the Commission intends that there be at least two AIMM inspections during that year. The Commission also removed the phase-in schedule for storage tanks inspections (within 90 days of January 1, 2016 for storage tanks ≥ 6 and within 30 days for storage tanks > 50 tpy) as those schedules have passed. The Commission updated the recordkeeping requirements for AIMM inspections to be consistent with the LDAR recordkeeping in Section II.E. Records of AIMM inspections under Sections II.C. and II.E. may be maintained together, and need not be kept separately.

The Commission has also strengthened monitoring requirements for storage tanks and associated equipment. In Section II.C.1.d., the Commission has determined that it is cost effective and feasible, while already on-site for visual inspection, to check the dump valve on the separator to ensure that it is not stuck open or visibly clogged. The Commission does not intend that operators will need to manipulate equipment or stay on-site for the purpose of observing actuation of the dump valve for purposes of this inspection requirement. The Commission has also determined that excess liquids in the vapor lines can cause a multitude of problems, including over pressurization of the tanks or smoking flares. Therefore, the Commission is directing operators to check liquid knockout vessels, when present, unless the vessel is set up to drain automatically, and to drain liquids if above the low-level indication point. If the knockout vessel is not equipped with a liquid level indicator, operators can comply with this requirement by draining the knockout vessel during the inspection. Further, for underground lines and above-ground lines where no knockout vessel is used, operators should establish a procedure by which they evaluate for the presence of liquids in the vapor lines, and drain as necessary. Appropriate operating and maintenance program documents should set forth this procedure so as to provide clarity on how an operator determines draining is necessary. These actions can be taken while the operator is already on-site for the inspections previously required, are consistent with actions the Commission generally understands operators are already taking in the field and therefore, the Commission does not expect these actions to create additional burden.

The LDAR program in Section II.E. (formerly Section XVII.F.) has required remonitoring following repair of a leak (as has Section I.L.). However, Section II.C. did not include an explicit remonitoring requirement following actions taken to address venting from storage tanks. Operators must now confirm that actions taken to address venting were effective through remonitoring. This confirmation must be made within 24 hours of the action taken to address the venting. This requirement does not reflect a timeframe in which the operator may address the venting without incurring liability for the violation. There is currently no regulatory period in which venting will not be considered a violation of Section II.C.2.a., unless the venting is reasonably necessary for one of the reasons expressly contemplated by Section II.C.2.a. Only where the initial emissions observation was observed through AIMM does the success of the response action need to be verified through AIMM. However, the Commission believes that if the venting was found with an IR camera and was addressed while the IR camera operator was on-site, then there is little to no burden to use the IR camera to confirm, for example, an effective seating of the thief hatch upon closure. In Section II.C.3.f., the Commission has established supplemental recordkeeping requirements when venting is observed and addressed.

In Section II.C.3.d., the Commission has strengthened recordkeeping requirements of inspections under Section II.C.1. These recordkeeping requirements are consistent with the recordkeeping required in Section I.F. (formerly Section XII.F.). The Commission has maintained the exemption from recordkeeping under Section II.C.3.b., for instances where venting is reasonably necessary for maintenance, gauging (unless a storage tank measurement system is required under and the operator complies with Section II.C.4.), or safety of personnel and equipment. However, the Commission expects that the emissions associated with these venting events will be reported in the annual emissions inventory.

Storage Tank Measurement Systems (Section II.C.4.)

Historically, operators have needed – for operational purposes – to open the thief hatch on storage tanks in order to sample and measure the level of the liquid to be sold (i.e., to determine quality and quantity). Technology has advanced over the past few years, including, without limitation, the use of Lease Automatic Custody Transfer (LACT) units, automated tank gauges, and the development of API 18.2 (Custody Transfer of Crude Oil from Lease Tanks Using Alternative Measurement Methods), which allow for the sampling and measurement of liquids without opening the thief hatch. It is the Commission's intention that owners and operators of facilities and tanks constructed after the deadlines in new Section II.C.4. must measure the level of the liquid (e.g., use tank level sensors) and sample the liquids (e.g., check for temperature, BS&W, and other indicia of merchantability) without opening the thief hatch. These storage tank measurement systems can be employed at facilities with and without automation.

Further, a significant number of operators have already deployed such systems at large and small facilities in the DJ Basin, in some cases voluntarily and in some cases as required pursuant to a Consent Decree or Compliance Order on Consent. The Commission notes that a storage tank management system may be different for tanks where liquids are both sampled and measured than for tanks where liquids are not sampled. For example, Commission understands that some produced water tanks are not sampled for quality, and therefore do not need to have equipment to allow for the sampling of the liquids without opening of the thief hatch.

Therefore, the Commission adopted a requirement to employ storage tank measurement systems to determine the quantity of the liquid at well production facilities, natural gas compressor stations, and natural gas processing plants constructed on or after May 1, 2020. Any such facilities that are constructed after January 1, 2021, must have storage tank management systems in place that determine both the quality and the quantity of the liquid. This requirement also applies to storage tanks at existing well production facilities, natural gas compressor stations, and natural gas processing plants that are modified by adding storage tanks. When operators add new storage vessels to existing facilities (e.g., to add capacity because production or throughput is expected to increase), they must outfit the new storage vessels and retrofit the existing vessels in the same battery with a storage tank management system. However, the ability to retrofit an existing battery may not exist, and is therefore not required, where a single storage tank is replaced due to maintenance concerns or where a tank is installed to provide extra head space in the vapor control system, but no production increase is associated with the installation.

The Commission has adopted minimal recordkeeping provisions for this requirement, including a description of the storage tank measurement system and records of the annual training program. The description must be sufficiently detailed to enable the Division to determine whether the operator is in compliance (e.g., sampling the liquids without opening the thief hatch). If an operator relies on a third party (e.g., hauler) to perform the gauging activities, those operators will need to work with the haulers to facilitate the training that will familiarize haulers with this new requirement.

The Commission has also adopted a requirement to allow for periodic calibration and testing of the storage tank measurement system. The Commission recognizes that while the Bureau of Land Management expressly allows for automatic tank gauging (see e.g. 42 C.F.R. Section 3174.3(33), incorporating by reference API 18.2), it can be necessary to test and calibrate the automatic tank gauging system. See 42 C.F.R. Section 3174.6(b)(5)(ii)(B). It is not the Commission's intent to adopt requirements at odds with the Bureau of Land Management. Further, some manufacturers may recommend inspection, testing, or calibration more frequently than specified by the Commission; the Commission intends to allow for those maintenance procedures, as reasonably necessary (i.e., the exception should not render ineffective the Commission's intent that thief hatches remain closed during the sampling and measurement process). Operators that perform maintenance procedures more frequently than semi-annually need to document the manufacturer's recommendation for the increased frequency and provide those materials to the Division upon request.

Hydrocarbon Liquids Loadout (Section II.C.5)

In Section II.C.5., the Commission has adopted new requirements to control or avoid emissions associated with the unloading of hydrocarbon liquids into transport vehicles (e.g., trucks). These requirements do not apply to produced water loadout. The Commission has determined to prohibit the venting of hydrocarbons during loadout activities, because the venting is not reasonably necessary within the meaning of Section II.C.2.a.; however, the Commission notes that some thief hatches may be "open" during loadout but are not emitting and are instead operating only as vacuum relief for the storage tank. An "open" pressure relief device that does not emit, but instead creates a vacuum, would not be a violation of the prohibition on venting during loadout, though the burden will remain on operators to demonstrate that any open pressure relief devices are not venting.

These requirements will apply to well production facilities, natural gas compressor stations, and natural gas processing plants constructed before and after May 1, 2020, with annual hydrocarbon liquid loadout throughput equal to or greater than 5,000 barrels per year, on a 12-month rolling basis. Throughput is based on the throughput of liquids loaded out to transport vehicles and does not include liquids loaded out to pipeline. Facilities constructed after May 1, 2020, must control emissions from loadout upon commencement of operation if they anticipate having a loadout throughput over 5,000 barrels per year. Facilities that are modified (e.g., new well drilled, well re-fracked or recompleted) that expect to have throughput over 5,000 barrels per year must also control loadout operations upon commencement of operation following the modification. Facilities that increase throughput such that loadout throughput reaches 5,000 barrels must control the emissions from loadout upon reaching 5,000 barrels. The Commission does not intend that operators may loadout more than 4,999 barrels of hydrocarbon liquids without controls. Thus, if an operator currently loads out to pipeline, and is not subject to this requirement, but the pipeline becomes unavailable (e.g., due to maintenance, whether scheduled or unscheduled) and the operator has 6,000 barrels stored in tanks, the operator must control the emissions from the loadout to transport vehicles or wait to loadout to transport vehicles until it can arrange for controls.

The Commission recognizes that compliance may be more cost effective at newly constructed facilities for several reasons. Operators may account for the vapors associated with loadout in the initial evaluation of air pollution control equipment required. Operators may also design the facility to make compliance easier, with both these requirements and Section II.C.4. However, the Commission has determined that it is also cost-effective and technically feasible to retrofit existing facilities to control loadout emissions. Operators using air pollution control equipment to control loadout emissions must also comply with other Regulation Number 7 requirements applicable to air pollution control equipment (e.g., inspections, recordkeeping). Further, if operators employ vapor collection and return systems, operators should include this vapor source in the engineering evaluation of their storage tanks and vapor control systems to avoid over-pressurizing the tanks.

The Commission has also established additional requirements to ensure the effective control of loadout emissions, including many requirements that the Division has previously established as permit RACT (under Regulation Number 3 and not as categorical RACT used for ozone SIP purposes) in loadout permits. The Commission determined that observation of and/or training and signage related to the loadout process by operators will help ensure that new staff and third parties are effectively implementing these requirements. The Commission directed the Division to develop a template and/or guidance regarding expectations for signage. However, if tanks are loaded out less frequently than monthly, the observation needs to take place during loadout when it does occur, unless observation is not feasible. If observation is not feasible (e.g., the operator did not receive notice of the loadout, which occurred during the middle of the night when no operator personnel was on site), the operator must inspect the facility within 24 hours to ensure that loadout equipment was properly stored and that thief hatches were closed. The Commission encourages the Division to work with operators to better understand when observation is, or is not, feasible.

Leak Detection and Repair (Section II.E)

In SB 19-181, the Legislature directed the Commission to minimize emissions from the oil and gas sector, including the gathering and boosting segment (i.e., compression). In conjunction with this directive, SB 19-181 further instructed the Commission to consider semi-annual monitoring for leaks at well production facilities. Therefore, the Commission has revised the LDAR program of Section II.E. (formerly Section XVII.F.) to increase the frequency of approved instrument monitoring method (AIMM) inspections to semi-annual at compressor stations with emissions between 0 and 12 tpy VOC and at well production facilities with emissions between 2 and 12 tpy VOC. Phase-in of these new inspections begins in 2020, and the Commission expects that operators will conduct the first semi-annual inspection prior to the start of the summer ozone season (i.e., May 1, 2020). Current requirements in place for larger facilities to inspect on a more frequent basis remain unchanged.

The Commission adopted a proposal to require enhanced leak detection and repair requirements for facilities within 1,000 feet of an occupied structure. The commission also directed the Division to work on a proposal that would speed up repair times in these areas and bring forward for the Commission's consideration in a future rulemaking hearing as soon as possible.

There are no other substantive changes to the existing LDAR program.

Emissions Associated with Well Maintenance, Unloading, and Plugging Activities (Section II.G)

In 2014, the Commission adopted a requirement that operators use best management practices (BMPs) to minimize hydrocarbon emissions and the need for well venting associated with well liquids unloading and well maintenance. The Commission is replacing the term "venting" with "emissions" or "emitting" to ensure consistency with the Common Provisions definition of "emission" and to avoid any confusion with the new definition of "venting" that was added to Section II.C.2.a.(i) (formerly Section XVII.C.2.a.(i)) in 2017, though no change in meaning or applicability is intended. The Commission has determined that BMPs should also be employed to reduce emissions from the well associated with well plugging activities. These activities have been increasing in frequency in the DMNFR in recent years, and the Commission finds that BMPs are a cost-effective and flexible proactive strategy to address this emerging emissions source. BMPs include both practices that reduce the need for well liquids unloading or well maintenance activities and practices that reduce or control emissions resulting from the well maintenance, well liquids unloading, and well plugging activities.

The Commission has also clarified and strengthened the recordkeeping and reporting requirements associated with the well emissions and BMPs. The inventories that will be required to demonstrate attainment with the ozone NAAQS in future SIPs necessitate detailed information on the emissions associated with these activities. Further, understanding BMPs employed to reduce or eliminate these emissions will assist the Commission in developing both voluntary and regulatory strategies to make further progress towards attainment. In an effort to minimize duplication with the new emissions inventory in Section V., the Commission intends that all information associated with activities covered by this Section II.G. will be reported on a separate form and not as part of the Section V. inventory. While recordkeeping is to begin in July 2020, the Commission understands that current methods of reporting emissions from these activities may need to be updated or improved in the future, and the Commission directs the Division to work with stakeholders to update emission factors and/or calculation methods as necessary.

Miscellaneous

Section II.C.2.a. prohibits the venting of hydrocarbons, unless reasonably required for maintenance, gauging, or safety. The Commission now clarifies that venting during gauging is expressly prohibited under this requirement where a storage tank measurement system is required under Section II.C.4. If Section II.C.4. allows for the opening of the thief hatch, that activity will not be considered venting within the meaning of Section II.C.2.a.

The Commission has revised Section II.C.2.b.(i), to reflect its intention in adopting the STEM provisions in 2014. The Commission intended in 2014, and specifically noted in the Statement of Basis and Purpose at that time, that STEM plans should include an analysis of the engineering design of the storage tank and associated air pollution control equipment (i.e., the vapor control system) to ensure that storage tanks are not over pressurized, causing excess emissions. The Commission believes that operators now largely understand and comply with this requirement, but has clarified the language in the rule itself principally to aid operators that may be new to the control program as a result of the new, lower control threshold. The Commission notes that this requirement does not require that operators maintain a site-specific design analysis for each facility. Worst-case design analyses or like-kind design analyses for similarly configured facilities may be utilized; however, the burden remains with the operator to show that the design analysis provided for the facility demonstrates adequacy of design.

Further, the Commission acknowledges that closed-loop tank pressure control systems designed to maintain tank pressures below a specified point can be, if designed and operated properly, indicative of adequate design. The Commission also acknowledges that design analyses do not need to be maintained within the STEM plan itself, so long as the STEM plan contains a description of the design analysis method employed and specifies the name and location of the design analysis for each facility covered by that STEM plan.

Pneumatic Controllers (Part D, Section III.)

SB 19-181 also directed the Commission to consider a requirement to reduce emissions from pneumatic devices. In the 2017 emissions inventory for the Moderate area ozone nonattainment SIP, pneumatic devices were identified as the second largest oil and gas area source (after tanks). In 2017, the Commission convened the Statewide Hydrocarbon Emission Reduction (SHER) team, to consider measures – both regulatory and voluntary – to reduce hydrocarbon emissions from the oil and gas sector. The Commission, at the same time, also established the Pneumatic Controller Task Force (PCTF), with a mission to collect and review data about pneumatic controllers and identify ways to reduce emissions from that equipment. After almost two years of work, the SHER team developed an early recommendation concerning pneumatic controllers, which the Commission has now adopted.

The SHER team supported a three-prong approach. First, the expansion of the pneumatic controller inspection and enhanced response program state-wide. Second, the SHER team recommended including language in this Statement of Basis and Purpose, directing the continued work to evaluate the use of zero-bleed pneumatic devices. Third, the SHER team supported a compliance assistance approach for operators outside the nonattainment area, while those operators get up to speed on the pneumatic controller inspection and enhanced response program that has been implemented in the nonattainment area since 2018.

The Commission approves of this approach and commends both the SHER team and PCTF for their work since 2017, building the knowledge that informed provisions of this rulemaking. The Commission has therefore expanded the pneumatic controller inspection and enhanced response program state-wide. At the same time, the Commission recognizes that there is much to learn about the inspection and maintenance of natural gas-driven pneumatic controllers outside the nonattainment area, which highlights the need for enforcement discretion. The Commission intends that for operations outside the nonattainment area, the determination of whether a pneumatic controller is operating properly will be made by the owner or operator, with minimal oversight by the Division for the first year of implementation.

The Commission further directs the SHER team and PCTF to continue their work on the mandates established in 2017, and to bring back to the Commission in 2020 their recommendations on the use of zero-bleed pneumatic devices. Specifically, the Commission continues to direct the PCTF to make recommendations on its findings in a report to the Commission in May 2020. However, the Commission revises its directive to the SHER team to present recommendations by no later than January 2020, to by no later than July 2020. This revised timeline will provide additional time for the SHER team to make any additional recommendations on cost-effective hydrocarbon emission reduction strategies evaluated by the SHER team. The Commission anticipates that the SHER team will also evaluate continuous methane emission monitoring and engage in discussions to determine actual leak rate percentages of components at oil and gas facilities for use in future rulemakings.

Downstream transmission (Part D, Section IV.)

SB 19-181 also directed the Commission to consider adopting a requirement that owners and operators of oil and gas transmission pipeline and compressor stations inspect and maintain all equipment and pipelines. The Commission's Regulation Number 7 has not historically regulated the transmission and storage segment, which includes pipeline, compressor stations, and other equipment transporting and storing natural gas downstream of the natural gas processing plant and prior to the distribution segment. Transmission pipelines, however, have been subject to federal and state pipeline safety regulations.

To address the new directive to minimize emissions from the transmission segment, the Commission adopted an innovative program that directs the setting of a methane intensity target and associated programmatic framework. This approach is the second recommendation from the SHER team, and again comes before the January 2020 deadline established by the Commission in November 2017. SHER team stakeholders involved in developing this program include trade associations, transmission segment operators, environmental and citizen groups, local governments, and the Division. The Division will approve a steering committee charter that will detail the purpose, responsibilities, and deliverables of the steering committee. The steering committee will develop an emissions protocol detailing the calculation and reporting of VOC, CO, NOx, ethane, and methane emissions and any associated program guidance documents or templates by September 30, 2020, determine a segment methane emissions intensity target by October 1, 2023, and certify initial target compliance based on the 2024 data. Each owner or operator in the segment will develop a company-specific best management practice (BMP) plan, the elements of which are enforceable by the Division. A goal of this program is continual improvement over time through review of BMPs, assessment of reported emissions and emissions intensity, and analysis of other data and best practices. In furtherance of this goal, the steering committee will periodically reassess the emissions intensity target and may consider, among other factors, the potential to reduce emissions from events beyond the control of the owner or operator.

The Division will provide an update on the development of the program to the Commission in 2021 as well as periodic updates regarding the progress of the program. The program will include a reporting element to demonstrate compliance and continual improvement. The steering committee will develop the criteria by which the industry participants will select a third-party contractor to collect and aggregate the company-wide reports into the segment-wide report prior to the first report due date of September 30, 2022. The third-party contractor, with involvement from the transmission segment owners or operators, may also provide VOC, NOx, and CO emissions data from the annual company-wide reports to the Division related to ozone modeling as needed and requested. Each year after the segment-wide emissions intensity target is established, the steering committee will submit a compliance certification to the Division that the transmission segment achieved the target. If such certification cannot be made, the steering committee will develop a plan for the segment to achieve compliance with the target. This plan, if needed, may include amendments to the program guidance documents, prescriptive control requirements, or other strategies to reduce methane emissions such that the transmission segment achieves the segment-wide emissions intensity target.

The inventory protocol may be based on existing EPA estimation and reporting mechanisms, specifically the EPA's Greenhouse Gas Reporting Program (GHGRP) and the Greenhouse Gas Inventory (GHGI). The emission estimation mechanisms may be updated as emission factors or calculation methods are revised. The inventory protocol will include the method(s) by which the transmission segment owners or operators will quantify and report emissions. The findings of the Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems (MAC) report (May 2016), among other data sources, may be used to develop the segment-specific methane emission reduction goals that, when combined, will achieve the transmission segment's emission intensity target in a cost-effective manner.

Annual inventory (Part D, Section V)

The Commission established an annual emissions reporting requirement to regularly update the Division's emissions inventory for equipment and activities in oil and gas operations. This inventory is intended to assist Colorado in ozone planning and the creation of emission inventories for use in ozone attainment modeling, as well as to comply with the directives in SB 19-181 to minimize emissions from the oil and gas sector. This inventory will provide missing information about oil and gas operations and will supplement the limited information provided on other aspects of those operations to assist the Commission in identifying emission sources appropriate for further emission reduction strategies.

Additionally, this inventory will also help Colorado move forward in beginning to address the broad greenhouse gas directives in SB 19-096 (Concerning the collection of greenhouse gas emissions data to facilitate the implementation of measures that would most cost-effectively allow the state to meet its greenhouse gas emissions reductions goals) and HB 19-1261 (Concerning the reduction of greenhouse gas pollution, and, in connection therewith establishing statewide greenhouse gas pollution reduction goals). This inventory is separate and apart from the APEN reporting and fee structure in Regulation Number 3, though the Commission expects that the Division, in consultation with stakeholders, will consider ways to align the reporting programs in the future to minimize duplication.

Operators will be required to submit a company-wide report on June 30 of each year for the preceding year. The first report will be due on June 30, 2021, covering emissions from July 1, 2020, through December 31, 2020. Operators are required to use the Division-approved form. The Commission expects that the Division will consult with stakeholders in the development of this form (or forms). The Commission understands that some of the emissions source category activities and equipment are not currently well defined, nor is there necessarily a well understood method of calculation for emissions (e.g., downhole well maintenance). The Commission therefore directs the Division to work with stakeholders from the adoption of this regulation throughout 2020 to, among other things: (1) appropriately define each emissions source category, activity, and equipment; and (2) identify reasonable methods of calculation for each emissions source category activity and equipment. For some emissions source category activities and equipment, achieving both goals may not be realistic before recordkeeping must begin in July 2020. Therefore, for those limited categories, the Commission expects that the Division will identify parameters that may be reported (e.g., frequency and duration) until such time as the category can be well defined and an appropriate calculation method can be identified. The Commission's intent here applies also to the well emissions reported under Section II.G.

Operators will need to include actual emissions information for various air pollutants, specifically methane, ethane, VOC, CO and NO_x, for each emissions source category activity and equipment, as well as company-wide. The Commission has determined that monthly emissions information should be submitted for the summer months (May through September), while emissions for the remaining months can be aggregated into the annual figures. The Commission recognizes that, over time, these emissions inventories are likely to reflect ongoing emission reductions from the industry resulting from both the continued implementation of emission reduction strategies and the refinement of emissions estimation techniques. The Commission also recognizes that the emission estimation techniques used for inventory purposes may differ from regulatory methods for calculating, recording, and reporting emissions under the APEN and permitting program, and intends that such differences will be considered in any enforcement matter. It is critical that these inventories be as accurate and complete as possible, and operators are expected to perform quality assurance on the data prior to submittal. However, these inventories will require the submittal of a large amount of information, so operators are provided with timeframes for correcting information found to contain substantive errors.

The Commission directed the Division to report back to the Commission in 2020 regarding the inventory and progress made.

Ozone State Implementation Plan Revisions for Serious Reclassification (Part C, Section II.F. (new section in former Section X.; Part E, Sections II. and III. (formerly Sections XVI.D. and XIX.))

Due to the reclassification to Serious, Colorado must submit revisions to its SIP to address the CAA's Serious ozone nonattainment area requirements, as set forth in CAA Sections 172 and 182(c) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (See 80 Fed. Reg. 12264 (March 6, 2015)). A Serious SIP revision must include provisions that require the implementation of RACT for major sources of VOC and/or NO_x (i.e., major stationary sources that emit or have the potential to emit 50 tpy or more) and for each category of VOC sources covered by a Control Technique Guideline (CTG) for which Colorado has sources in the DMNFR.

Therefore, to address the CAA Serious RACT SIP requirements, the Commission adopted revisions to Regulation Number 7 to include RACT requirements in Colorado's ozone SIP for 50 tpy major sources of VOC and/or NOx (which became major sources as of the effective date of the reclassification to Serious). The revisions include expanding the applicability of the combustion equipment requirements, including the combustion process adjustment requirements, in Section II. to equipment located at facilities with NOx emissions greater than or equal to 50 tons per year; incorporating by reference NSPS and/or NESHAP requirements for specific points at some 50 tpy major sources in Section III.; requiring some sources submit RACT analyses to the Division in Section III.; and a new categorical rule regarding general solvent use in Part C, Section II.F.

Consistent with Senate Bill 19-181, House Bill 19-1261 and Senate Bill 19-096, the Commission directs the Division to propose regulatory recommendations to the Commission in 2020 regarding: pneumatic devices that do not vent gas; continuous emission monitoring; alternatives to combustion for emissions control; enhanced LDAR, especially near occupied dwellings; and other options to "minimize emissions of methane and other hydrocarbons, volatile organic compounds, and oxides of nitrogen from oil and natural gas exploration and production facilities and natural gas facilities in the processing, gathering and boosting, storage, and transmissions segments of the natural gas supply chain," Colo. Rev. Stat. Section 25-7-109(10)(a), including "pre-production activities, drilling, and completion," id. Section 25-7-109(10)(c).

To increase transparency and accountability, the Commission further directs that in 2020 the Division explore options for developing a publicly accessible and searchable oil and gas complaint filing and tracking tool, and to accept public input on the development of this tool. The Division will report back to the Commission on its progress in 2020.

SIP streamlining (Part B, Sections IV. and VII. (formerly Sections VI. and XV.) and Appendices B, C, and E)

As a SIP clean-up effort, the Commission adopted revisions to Regulation Number 7, Part B, Sections IV. and VII. and removed Appendix E so the requirements align with current EPA methods and requirements.

In 1980, the Commission adopted requirements in Regulation Number 7, Section IV. requiring an annual pressure test for gasoline transport trucks. Those requirements were based on EPA's Control Techniques Guidelines (CTG) Control of Volatile Organic Compound Leaks from Gasoline Tank Trucks and Vapor Collection Systems (December 1978) and included the test procedures for annual pressure and vacuum testing of gasoline transport trucks, as outlined in Appendix E. In 1980, The Commission also adopted Appendix B which specifies the criteria for controlling vapors from gasoline transfer to storage tanks. Those requirements are based on EPA's CTG Design Criteria for Stage I Vapor Control Systems Gasoline Service Stations (November 1975). EPA approved these provisions into Colorado's SIP in 1995.

Since the publication of EPA's CTGs, EPA has published similar requirements for gasoline transport trucks in EPA's NSPS Subpart XX Standards of Performance for Bulk Gasoline Terminals (40 CFR Part 60, Subpart XX (August 18, 1983, last revised December 19, 2003)); NESHAP R National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations) (40 CFR Part 63 Subpart R (December 14, 1994, last revised April 6, 2006)); NESHAP Subpart BBBBBB National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities (40 CFR Part 63, Subpart BBBBBB (January 10, 2008, last revised January 24, 2011)); and NESHAP Subpart CCCCCC National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities (40 CFR Part 63, Subpart CCCCCC (January 10, 2008, last revised January 24, 2011)). These federal standards reference EPA's Method 27, Determination of Vapor Tightness of Gasoline Delivery Tank Using Pressure Vacuum Test, in contrast to the CTG's pressure-vacuum test.

The Commission adopted provisions to replace the outdated vacuum-pressure test in Regulation Number 7 with the more current EPA Method 27. The Commission also updated the test values in Regulation Number 7, which are based on EPA's CTG but also correspond to the EPA Method 27 test values in EPA's NSPS XX, NESHAP R, NESHAP BBBBBB, and NESHAP CCCCCC. The Commission also revised the recordkeeping and certification requirements in Section IV. to correspond to EPA's Method 27 and federal standards. Lastly, the Commission clarified the requirements for owners or operators using vapor collection systems that such systems must be leak-tight and properly maintained and operated.

These revisions will update Colorado's SIP and align the gasoline transport truck, terminal, and service station control and testing requirements with current EPA NSPS and NESHAP standards.

Miscellaneous

The Commission has also adopted revisions to provisions not discussed in detail above in order to facilitate and align the substantive revisions identified, including revisions to the Applicability in Part A, Section I.A., and exemptions in Part A, Section II.B.

Further, these revisions will correct any typographical, grammatical, and formatting errors found within the regulation.

Incorporation by Reference

Section 24-4-103(12.5) of the State Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of Section 24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission included reference dates to rules and reference methods incorporated in Regulation Number 7, Part E, Section II.

Additional Considerations

Colorado must revise Colorado's ozone SIP to address the ozone serious nonattainment area requirements. The Clean Air Act does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to satisfy Colorado's serious nonattainment area obligations.

The Commission also adopted revisions to Regulation Number 7 that are unrelated to the reclassification to serious to update and streamline requirements for gasoline transport trucks, terminals, and service stations to align with current federal requirements; therefore, these revisions do not exceed or differ from the federal act or rules thereunder. Further, the Commission adopted revisions to Regulation Number 7 to achieve further emission reductions in the oil and gas sector.

In accordance with Sections 25-7-105.1 and 25-7-133(3), CRS, the Commission states the rules in Part D, Sections II. (except II.C.1.b.(ii) and II.F.), III.F., IV., and V. of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time.

These revisions do not exceed or differ from the federal act due to state flexibility in determining what control strategies to implement to reduce emissions. However, where the proposal may differ from federal rules under the federal act, in accordance with Section 25-7-110.5(5)(b), C.R.S., the Commission determines:

- (I) The revisions to Regulation Number 7 address equipment and operations in the oil and gas sector including storage tanks, storage tank loadout, fugitive emissions from components, pneumatic controllers, and downstream transmission operations. The proposed revisions also include an annual oil and gas sector emissions inventory report. NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, NESHAP HHH, the Greenhouse Gas Reporting Program (GHGRP), and Pipeline and Hazardous Materials Safety Administration (PHMSA) may also apply to such oil and gas facilities and operations. The revisions to Regulation Number 7 apply on a broader basis to more storage tanks and fugitive emissions components than the NSPS and NESHAP and more facilities and operations than the GHGRP and PHMSA.

The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and/or NOx (> 50 tpy) in the SIP. Specifically, the Commission revised Regulation Number 7, Part E, Sections II. and III. to include categorical RACT requirements for combustion equipment at major sources of NOx and incorporate by reference federal standards for specific sources or points. MACT DDDDD, MACT JJJJJ, MACT ZZZZ, MACT YYYY, NSPS GG, NSPS KKKK, NSPS IIII, and NSPS JJJJ may apply to such combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to more combustion equipment. The Commission also revised Regulation Number 7 to include categorical RACT requirements for general solvent use and is not aware of federal rules applicable to general solvent use.

- (II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies or work practices to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold. EPA has also provided some flexibility in NSPS OOOOa by allowing a company to apply to EPA for an alternative means of emission limitations for fugitive emissions components.
- (III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. Similarly, EPA develops NSPS or NESHAP considering national information and data, not Colorado specific issues or concerns. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here.
- (IV) In addition to the 2008 ozone NAAQS, Colorado must also comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS. The current revisions also attempt to maintain the air quality in areas of Colorado currently attaining the NAAQS; should an area slide into nonattainment, a nonattainment area designation would likely result in the imposition of costlier retrofits.
- (V) EPA has established a Serious SIP-RACT implementation deadline of July 20, 2021, for strategies not needed for any attainment demonstration. There is no timing issue that might justify changing the time frame for implementation of federal requirements.

- (VI) The revisions to Regulation Number 7 Part D, Sections I. through IV. strengthen Colorado's SIP state-only provisions. These sections currently address emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry. The revisions to Regulation Number 7, Part C, Sections II.F. recognize practices currently utilized by solvent operations. The revisions to Regulation Number 7, Part E, Sections II. and III. are also specific to existing emission points at major sources of VOC and NOx, allowing for continued growth at Colorado's major sources.
- (VII) The revisions to Regulation Number 7 Part D, Sections I. through V. establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources. The revisions to Regulation Number 7, Part C, Sections II. and Part E, Section II. similarly establish the categorical RACT requirements for similarly situated and sized sources.
- (VIII) If EPA does not approve Colorado's SIP, or if Colorado continues to fail to achieve the NAAQS, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. This outcome may subject others to increased costs.
- (IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements. The revisions to Regulation Number 7 establishing an annual oil and gas inventory report are different than EPA's GHGRP in that more sources will be required to report under Regulation Number 7. This is necessary for Colorado to better understand the oil and gas emission sources and the opportunities to pursue additional emission reductions. Newly enacted legislation in Colorado has also established a compelling reason to adopt the monitoring, recordkeeping, and reporting requirements in the revisions.
- (X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for storage tanks and component leaks. Other revisions reflect changes in industry practice, such as for solvent use. Similarly, the revisions concerning major sources of VOC and NOx generally reflect current emission controls and work practices.
- (XI) The revisions adopted will reduce significant amounts of VOC and methane, addressing both Colorado's ozone problems and making strides to reduce the impact of climate change. As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will reduce emissions in a cost-effective manner.
- (XII) Alternative rules could also provide reductions in ozone, VOC, NOx, methane, and other hydrocarbons to address SB 19-181 and help to attain the NAAQS. SB 19-181 specifically directs the Commission to "consider" revising its rules to adopt more stringent requirements related to LDAR, pneumatic devices, monitoring, and the transmission segment. The Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an unapprovable SIP.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in CRS Section 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the serious nonattainment area requirements. However, to the extent that CRS Section 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

- (I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.
- (II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of methane, VOCs, and other hydrocarbons.
- (III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.
- (IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.
- (V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

Hundreds of people from across the state submitted written comments on the proposed changes to Regulations 3 and 7. Most of these written comments called for additional regulation of oil and gas operations, to fulfill the directives of SB 19-181, protect public health, and reduce greenhouse gas emissions. Prior to the rulemaking hearing, the Commission held public comment sessions in Rifle, Durango, and Loveland, on December 10, 11 and 16, respectively. Dozens of members of the public spoke at each of these sessions. Many commenters expressed support for the proposed changes to Regulations 3 and 7, citing concerns about risks to health and to the climate from oil and gas emissions. Many commenters at the Rifle and Durango meetings emphasized the need for rules to be applied statewide. Commenters also called on the Commission to develop requirements for continuous monitoring of oil and gas emissions. Some speakers at each comment session expressed concern that the industry was being overregulated, with some on the Western Slope emphasizing that their part of the state was in attainment with ozone standards and expressing concerns with the impact more stringent rules might have on the industry.

T. September 17-18 & 23, 2020 (Part D, Sections II., IV., V., VI. and Part E, Section I.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the Colorado Administrative Procedures Act § 24-4-103(4), the Colorado Air Pollution Prevention and Control Act, Colorado Revised Statutes (CRS) §§ 25-7-110 and 25-7-110.5., and the Air Quality Control Commission's (Commission) Procedural Rules.

Basis

The Commission revised Part E, Section I. to reduce emissions from natural gas fired reciprocating internal combustion engines (RICE) greater than or equal to 1,000 horsepower (hp) on a state-wide basis. The revisions are in response to four distinct directives to secure reductions: Senate Bill 19-181 (SB 19-181); the second implementation period of the Regional Haze Rule pursuant to Clean Air Act Section 169A; progress towards the 2008 ozone National Ambient Air Quality Standard (NAAQS) of 75 ppb and 2015 ozone NAAQS of 70 pp; and to address nitrogen deposition at Rocky Mountain National Park (RMNP).

The Commission also revised Part D, Sections II.G., IV., and V. to include annual reporting of carbon dioxide (CO₂) and nitrous oxide (N₂O) and Section V. to include additional emissions reporting from class II disposal well facilities. The Commission adopted a new Part D, Section VI. requiring owners and operators of pre-production oil and gas operations to monitor pollution during pre-production (i.e., drilling through flowback) and early-production and to control emissions from pre-production tanks and vessels (i.e., flowback vessels). Lastly, the Commission expanded the requirements in Part D, Section II. to control emissions from hydrocarbon liquids loadout at class II disposal well facilities. These proposed revisions are a next step in addressing the directives of SB 19-181, SB 19-096, and HB 19-1261, building upon revisions adopted by the Commission in December 2019.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, Sections 25-7-101, CRS, et seq. (Act), specifically § 25-7-109(10) directs the Commission to adopt emission control regulations to minimize emissions of methane, other hydrocarbons, VOC, and NO_x from oil and gas operations. Sections 25-7-109(1)(a), (2), and (3) authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources; emission control regulations pertaining to NO_x, hydrocarbons, and hazardous air pollutants; and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Section 25-7-105(1) directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in § 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere (and, as such, includes VOC, NO_x, methane, and other hydrocarbons) and provides the Commission broad authority to regulate air pollutants.

Purpose

To address SB 19-181, SB 19-096, HB 19-1261, ozone, visibility, and nitrogen deposition, the Commission adopted revisions to Regulation Number 7 that limit emissions from engines, limit emissions from pre-production tanks, reduce emissions from hydrocarbon liquids loadout at class II disposal well facilities, require reporting of emissions from class II disposal well facilities, expand annual reporting to include additional greenhouse gases, and require monitoring at pre-production and early production oil and gas operations. These revisions are all adopted on a state-wide and state-only basis.

Engines (Part E)

The Commission adopted requirements in Part E, Section I. to minimize emissions from natural gas fired RICE. The requirements apply to natural gas fired RICE greater than or equal to 1,000 HP. The requirements are responsive to SB 19-181 as it applies to engines used in the oil and gas sector, as well as securing NO_x reductions that will also reduce ozone, visibility, and nitrogen deposition at RMNP.

Except for the combustion process adjustment requirements for engines at major sources, the Commission has not revised the requirements pertaining to engines since 2010, and emissions from engines associated with oil and gas production in Colorado have continued to increase. While the Commission recognizes the twin challenges currently faced by the oil and gas industry in Colorado - the COVID-19 pandemic and low oil prices - this regulation's provisions for phasing in compliance over time and, particularly, the unique characteristics of the Alternative Company-Wide Compliance Plan (Company-Wide Plan, affords the industry the flexibility necessary to achieve emission reductions necessary to protect public health and the environment in a cost effective manner.

Applicability (Section I.D.5.a.)

The Commission adopted a new subpart, Section I.D.5., to establish state-only standards to reduce emissions from a subset of existing stationary engines operating over or equal to 1,000 HP and those placed in service, modified, or relocated after November 14, 2020. As defined in the rule, "placed in service" addresses when an engine is brought to a site for utilization. "Placed in service" is a new term that deviates from the Division and industry's traditional reliance on the defined term "commence construction" or NSPS JJJJ's reliance upon manufacture date.

The Commission is clarifying when replacement of an engine under an authorized alternative operating scenario (AOS) would not trigger the engine to be subject to the standards in Table 2 for engines "placed in service" after November 14, 2020. Subsequent replacements under an authorized AOS also would not trigger the replacement engine to be subject to the standards in Table 2 for engines "placed in service" after November 14, 2020. If an engine is replaced under an AOS, while it may not trigger the lower standards based on "placed in service," it may nonetheless trigger the lower standards if it is "relocated" – i.e. if the replacement engine is brought into Colorado from outside Colorado, or brought into the nonattainment area from outside the nonattainment area. The return of an engine to the same site from which it was removed for the sole purpose of repair or maintenance is not considered "placed in service" or "relocated" for purposes of this Section I.D.5.

The Commission also adopted a different framework for "relocated" engines in Regulation Number 7, Part E, then in Regulation Number 6, Part B, which provides that engines brought to a site from another location in Colorado are not considered "new" and are not subject to the more stringent standards of the applicable NSPS. Under Regulation Number 7, there are only two exceptions to when an engine is considered new: when an engine is replaced under an alternative operating scenario (AOS) in an existing permit, which requires the engine to meet the same standards as the engine replaced, or when an engine subject to a Company-Wide Plan is moved from one site to another site with the same owner or operator. When an engine is subject to a Company-Wide Plan, the operator will have more flexibility to move an engine as long as it achieves at least the same emission reductions under the plan. However, an engine brought into the 8-Hour Ozone Control Area is considered "relocated" and must meet or exceed the standards as of the date it begins operation, whether or not it is subject to a Company-Wide Plan.

Emission Standards (Section I.D.5.b.)

The Commission adopted different emission standards based on engine configuration and the date that the engine was placed in service, modified, or relocated. The Commission intends that the applicable engine configuration is determined by the most current Division-issued permit or APEN filed prior to November 14, 2020. If the engine configuration is not identified in a Division-issued permit or APEN, the owner or operator is required to submit an APEN with this information to the Division by May 1, 2021. After November 14, 2020, any change to the identified configuration that results in an emissions increase is considered a modification.

The Commission adopted, generally, more stringent NO_x standards applicable to engines placed in service, modified, or relocated after November 14, 2020. However, for 2-stroke lean burn engines, the NO_x standard is the same whether the engine is currently in use at a site or brought on at a later date. The Commission also intends that any engines subject to a more stringent standard under a permit or other rule, such as Section I.D.2.b. of Regulation Number 7, must still comply with that more stringent limit. The Commission adopted varying timing requirements for owners or operators to meet the emission standards, based on the location of subject engines inside and outside of the 8-Hour Ozone Control Area. Owners or operators with any engines in the 8-Hour Ozone Control Area are subject to a more aggressive timeline, which requires 100% of engines inside the 8-Hour Ozone Control Area to meet the emission standards by May 1, 2024, and 100% of engines outside the 8-Hour Ozone Control Area meet the emission standards by May 1, 2026. Operators with no engines inside the 8-Hour Ozone Control Area must follow the second timeline and meet the standards of at least 20% of engines each year from 2022 to 2026.

The Commission intends that the emission standards in Table 2 are a gram per horsepower-hour limit based on appropriate averaging times. The Commission also intends that operators demonstrate compliance with the certification and recordkeeping requirements through the performance testing results required by Section I.D.5.d and the portable analyzer results obtained in accordance with Section I.D.5.e., using the appropriate averaging times.

The Commission requests that the Division consider evaluating strategies to increase the electrification of engines, lower emissions standards for engines, and possible controls applicable to smaller engines.

Notification to Division (Section I.D.5.b.(iii))

If an owner or operator has subject engines, the owner or operator must submit a notice to the Division no later than May 1, 2021. However, the owner or operator of engines covered by a Company-Wide Plan will not need to submit the information required by Section I.D.5.b.(iii) for all engines.

Permit Modification (Section I.D.5.b.(iv))

The Commission adopted two deadlines for when a permit modification application is required. If the engine can meet the standards through only a permit modification, the application is due May 1, 2021. If the engine cannot meet the standards through only a permit modification, the application is due 365 days prior to that engine's compliance deadline. An example of the first scenario is where an engine currently permitted with a high emission rate can meet the standards if operated at a lower emission rate and it is, in fact, already operating as of November 14, 2020, at that lower emission rate. In contrast, an example of the second scenario is where an engine is permitted at an emission rate above the applicable standard and operates at its permitted level, which would require the operator to change the operation of the engine in order to comply. This engine, therefore, would have a compliance date in accordance with Section I.D.5.b.(v)(B), and the permit application would be due 365 days prior to that engine's compliance deadline. Stakeholders expressed concerns that the Division may not be able to timely process all of the permit modifications. Therefore, the Commission determined that the flexibility outlined in the rule was necessary for both industry and the Division. In the case of a pending permit modification, the Commission intends that the most current APEN requested limits will be used to determine compliance with the rule.

Industry stakeholders have expressed that the rules need to be more accommodating for Division delays in permit issuance for those situations where owners and operators cannot take action to comply with the emission standards without a permit in hand. Industry notes that without a revised permit, owners and operators would be out of compliance with federal and state permit requirements, leaving the operator with the choice of what standards to comply with. Based on information provided by these stakeholders, the Division believes that there are only 15 such permits. Additionally, the vast majority of engine upgrades do not necessitate a permit modification prior to completing the upgrade.

The Division has indicated that it has enough dedicated staff to complete the required permit modifications in a timely fashion so long as the operator submits the permit application at least one year in advance of the compliance deadline. To address stakeholder concerns, the Commission expects the Division to work with operators that require a permit prior to commencing upgrades and create a process to give these permit applications priority. Should any permits push up against the one-year issuance deadline, the Division, in its discretion, will evaluate any potential operator compliance deadline extensions on a case-by-case basis.

Alternative Company-Wide Compliance Plan (Company-Wide Plan) (Section I.D.5.c)

The Commission adopted a Company-Wide Plan option to allow flexibility for each owner or operator to develop a technologically and economically feasible timeline tailored to its individual operations to achieve the same or better emission reductions than would be achieved through compliance with the emission standards on an individual engine basis.

The Company-Wide Plan requires an overall emissions percentage reduction based on company-wide engine operations. Owners or operators using this option must demonstrate that the total NOx emissions allowed under the Company-Wide Plan are less than or equal to the total NOx emissions allowed through compliance with the emission standards on an individual engine basis. Engines included in a Company-Wide Plan remain subject to the performance testing, monitoring, recordkeeping, and reporting requirements.

This Company-Wide Plan option is available only to owners or operators with five or more engines that are subject to Section I.D.5.b(v)(B). For purpose of the Company-Wide Plan only, the term owner/operator refers to owners or operators that are participating in a Company-Wide Plan and are owned or operated by the same parent company. Engines that already meet the emission standards of Table 2 but only need a permit modification to reflect compliance may not be part of a Company Wide Plan for which credit is claimed by the operator. However, if the operator makes a further retrofit to the engine, the operator may include that engine in the Company Wide Plan and claim credit for the reductions achieved by the further retrofit. For example, if Engine A, a 4-stroke lean burn engine, has a permit limit of 1.8 g/hp-hr, but currently operates at 1.2 g/hp-hr, Engine A would not be included in the Company Wide Plan. However, if the operator installs additional control technology such that Engine A can now operate at 1.0 g/hp-hr, the emission reductions associated with the drop in emissions from 1.2 g/hp-hr to 1.0 g/hp-hr can be included in the Company-Wide Plan. Only physical retrofits, and not operational changes, can be accounted for in this manner.

Owners or operators will submit a notification (referred to as a compliance plan) using a Division-approved form that will be developed with stakeholder input. Recognizing that the Company-Wide Plan is intended to afford flexibility only where it will achieve the same or better reductions, the Commission has provided for detailed information to be submitted to the Division for review. The information submitted will allow the Division to compare the emission standards and operating conditions that an engine is meeting before and after the Company-Wide plan as well as the maximum emissions permissible if all Company-Wide Plan engines complied individually with the standards versus the permissible emissions under the Company-Wide Plan.

Owners or operators must calculate "Plan Emission Reductions" - i.e. a summation of NOx emission reductions from all engines in the Company-Wide Plan. This figure is calculated by looking at the maximum amount of NOx emissions from the engines before November 14, 2020 (using the current permitted emission rate) and subtracting the maximum amount of NOx emissions that will be allowed from those engines under the Company-Wide Plan.

Owners or operators must also demonstrate that the Company-Wide Plan will result in real emission reductions, and the Division is directed to disapprove any Company-Wide Plan that the Division determines does not achieve those reductions. Owners or operators will calculate the estimated historic emissions from the plan's engines in tons per year as a baseline, using the most stringent regulatory or permitted emission standards and operating conditions in conjunction with actual operating hours (averaged over 2017-2019). That baseline figure is then compared to the maximum amount of emissions permissible from the Company-Wide Plan engines to ensure that the Company-Wide Plan will result in emission reductions. The demonstration also includes a comparison of the emission reductions that would be achieved from the actual baseline figure if each engine complied with the emission standards on an individual basis to the reductions that will be achieved under the Company-Wide Plan. In this way, the Commission seeks to ensure that a Company-Wide Plan achieves demonstrable reductions in NOx emissions.

Owners or operators will not be allowed to utilize reductions in permitted operating hours to offset emission reductions that would otherwise be achieved where permitted hours are higher than actual hours of operation (on average over 2017, 2018, and 2019). For example, an operator with a permit to operate at 8,760 hours per year but that operated only at 5,000 hours per year (on average over 2017, 2018, and 2019) cannot modify its permit to lower the permitted hours of operation to 5,000 and thereby create NOx emissions for which it can take credit in its Company-Wide Plan.

Some stakeholders have expressed concerns over how engines that began operation during or after the averaging years will calculate "historic" emissions. For these types of engines, the Commission expects that the most recent year(s) of operation should be used to calculate "historic" emissions. If there is less than one year of operation during this time frame, the Commission expects that the operator should extrapolate the available operation emission data to one year to estimate "historic" emissions.

Owners or operators must also submit notice of relocated engines in the annual update to the Company-Wide Plan, beginning in 2022. A relocated engine will be categorized by its new location (inside or outside of the 8-Hour Ozone Control Area) for purposes of the engine's compliance deadline.

To assist with implementation, the Commission directs the Division to provide timely guidance to the regulated community as to how to develop a Company-Wide Plan. The Commission recognizes that the Company-Wide Plan provisions are complicated, and believes providing the following examples of how the Commission intends the program to work will be helpful.

Example 1:

An engine in a Company-Wide Plan is located inside the 8-Hour Ozone Control Area. It is moved from site A to site B (same owner/operator), also within the 8-Hour Ozone Control Area. The engine was not "placed in service" or "relocated" within the meaning of this rule, and compliance deadlines would not change. The owner/operator just submits the new location in its annual update.

Example 2:

An engine in a Company-Wide Plan is located outside the 8-Hour Ozone Control Area. It is moved from site A to site B (same owner/operator), except that site B is located inside the 8-Hour Ozone Control Area. The engine is not "placed in service" within the meaning of this rule but it is "relocated." The engine's relocation into the 8-Hour Ozone Control impacts both the standard with which it must comply and the timing of when the new standard must be achieved.

If the engine was not proposed for retrofit or if it was proposed for retrofit but under the Company-Wide Plan it would not meet the standard, the engine will need to meet the emission standards as of its date of operation following relocation. If the engine was proposed for retrofit to achieve performance below the emission standards (retrofit/shut-down, etc.), the engine must meet the more stringent of either the applicable standard or the proposed Company-Wide Plan standard as of the date of operation following the relocation date.

Conversely, if an engine subject to a Company-Wide Plan located in the 8-Hour Ozone Control Area is moved to a different site (same owner/operator) outside of the 8-Hour Ozone Control Area, the engine is not “placed in service” or “relocated” within the meaning of this rule. The engine must meet the standard specified in the Company-Wide Plan consistent with the applicable compliance date.

Example 3:

Operator A has 20 engines and submits a Company-Wide Plan that includes modifying five engines (in 2022 and 2023) and shutting down two engines (in 2024). Operator A then transfers ownership of one of the engines (either the engine or the entire facility) to be shut down to Operator B; that shutdown would have achieved 20 tons per year (tpy) NO_x reduction. Operator A must find an additional 20 tpy NO_x reduction from the 19 engines remaining in its Company-Wide Plan.

Example 4:

A Company-Wide Plan includes shutting down an engine. The operator then realizes it needs a replacement engine at that same site. The operator has a few options. First, the operator can amend its Company-Wide Plan to no longer shut down the engine (assuming the engine’s compliance deadline has not yet passed) and can identify other actions to be taken to achieve the emission reductions that would have otherwise been realized from the shutdown of the engine. Second, the operator can shut down the engine as originally intended and bring on a new engine. The new engine will be subject to the emission standards as an engine “placed in service” after November 14, 2020, and cannot be a part of the operator’s Company-Wide Plan because an engine scheduled for shut down under a Company-Wide Plan cannot be replaced with a different engine subject to the Company-Wide Plan. Because the operator must comply with the Company-Wide Plan, the operator will still need to cancel the APEN and permit for the existing engine and permit the new engine as a new source.

Example 5:

An operator has ten engines subject to a Company-Wide Plan and intends to modify five of those engines to achieve the required Plan Emission Reductions. However, in order to meet the CO standards for one of the engines that will not be modified to achieve Plan Emission Reductions, the operator must make an adjustment that has the effect of increasing NO_x emissions from that engine. In calculating the maximum allowable NO_x emissions from engines in the compliance plan and Plan Emission Reductions required, the operator must account for the increase in NO_x emissions from the engine.

Performance Testing, Monitoring, Recordkeeping, and Reporting (Sections I.D.5.d., I.D.5.e., I.D.5.f., and I.D.5.g.)

The Commission adopted performance testing requirements to establish a baseline for evaluating an engine’s performance – i.e. to enable an operator to know whether the engine was meeting the standards already or how much action might be required to meet the standards. To conserve the resources of both the Division and the operators, the Commission has allowed for operators to rely on existing ongoing semi-annual portable analyzer testing requirements, as well as performance testing conducted under NSPS JJJJ, a permit, or testing conducted voluntarily after January 1, 2020.

The Commission also adopted semi-annual portable analyzer testing requirements. The portable analyzer monitoring must commence within twelve (12) months of the initial performance test. The Commission intends that operators will conduct two portable analyzer tests in 2022, the first of which must be completed by June 30, 2022.

The Commission has also adopted new monitoring, recordkeeping and reporting requirements. With respect to oil and filter changes under Section I.D.5.e.(iv)(A), the Commission acknowledges that the development of an oil analysis program that tests to ensure that oil does not need to be changed meets the requirements of that section.

In the recordkeeping section, the Commission requires that for both performance tests and portable analyzer tests, the owner or operator retains records regarding the date, engine settings on the date of the test, and documentation of the methods and results of the testing/monitoring. The Commission acknowledges that maintaining the test reports (for performance tests) and maintaining records consistent with the Division's Portable Analyzer Monitoring Protocol (for portable analyzer test), is sufficient to demonstrate compliance with the requirements to maintain the date, engine setting on the date of the test, and documentation of the methods and results of the testing/monitoring. The Commission has required the reporting of the results of performance tests (Section I.D.5.g.(i)) and semi-annual portable tests (Section I.D.5.g.(iv)). By "results," the Commission means that the owner/operator shall indicate whether the tests were passed or failed. Other, more detailed results are required to be maintained as part of the recordkeeping requirements and will be available to the Division upon request.

General provisions (Section I.D.2.)

In 2019, the Commission adopted a reorganization of Regulation Number 7 moving like-sections together, including engines. The Commission now completes the reorganization of the engine sections by duplicating the applicable general provisions that applied to engines in Part D, Section II. (formerly numbered Section XVII.) in Part E, Section I.D.2. These provisions will continue to apply to engines addressed in Part E, Sections I.D.3. and I.D.4. (formerly Sections XVII.E.) and will also apply to engines addressed under the new Part E, Section I.D.5.

Oil and gas operations (Part D)

The Commission expanded or adopted additional requirements in Part D to further minimize emissions of greenhouse gases, ozone precursors, and other hydrocarbons from the oil and gas sector.

Pre-production and early production monitoring

The Commission adopted a new Section IV. that requires owners or operators to monitor air quality at and/or around pre-production operations (i.e., drilling, fracturing, drill-out, flowback) and early production operations (i.e., six months). The purpose of this air quality monitoring is multi-faceted in that the Commission anticipates the monitoring program will gather information about the evolving oil and gas monitoring technologies, data about potential emissions during pre-production and early production operations (e.g., ozone precursor emissions, greenhouse gas emissions, hazardous air pollutants), and inform future monitoring efforts. Owners or operators will also monitor air quality for ten days prior to beginning pre-production operations. The Commission recognizes that ten days does not provide a comprehensive or long-term baseline but intends that it cover day-of-week variability in surrounding activities and short-term meteorological variability, in order to provide a reference point for interpreting subsequent data.

Owners or operators must submit an air quality monitoring plan to the Division for approval prior to monitoring air quality. The Commission created a flexible air quality monitoring program that allows the operator to specify what pollutant(s) representative of pre-production and early production hydrocarbon emissions will be monitored and by what monitoring technology. The Commission anticipates that the additional elements of the air quality monitoring plan, such as monitor siting, frequency of measurements, monitoring equipment limitations, and ability to trigger or collect speciated samples, will vary based on the monitoring objectives and technology utilized. The Commission also anticipates that the response level(s) will vary based on the monitoring technology, monitor placement, the pollutant(s) monitored, data collection and averaging times, and other factors. The response level may differ from a lower detection level established by the owner or operator that triggers an initial investigation of potential emissions at the facility. The Commission expects that the monitoring technology selected will have a detection ability sufficient to detect the pollutant(s) monitored at an appropriate level above area concentrations such that the monitoring objectives (e.g., detect ozone precursors, detect hazardous air pollutants, detect greenhouse gas emissions, associate elevated monitored values to an emission source within the monitored operations) are achieved. The Commission recognizes that not every elevated measurement constitutes a detection requiring a response but instead may be accompanied by analytics evaluating the measurements in comparison to an emission source or activity. The Commission also expects that placement of the monitors will be designed to be adequate to meet the objectives of the monitoring plan and that operators will select a monitoring technology that collects measurements at short-term intervals (e.g., 1 minute, 15 minutes, 1 hour) and appropriate sensitivity.

For example, concentrations at 2000-4000 feet away from the operations are likely to be low and, therefore, would require high-sensitivity instruments; monitors placed in close distance to the operations may need to be placed at variable heights to detect emissions from equipment of different heights; or monitors may need to be placed in both upwind and downwind locations, depending on the monitoring technology. In addition, the Commission expects the Division to work with operators in approving air quality monitoring plans to make sure that local jurisdiction air quality monitoring requirements and COGCC site preparation requirements are considered. The Commission expects the Division to consult with relevant local governments in reviewing monitoring plans, to obtain their input on local circumstances or concerns that may guide the Division's determinations on plan adequacy.

Owners or operators will also submit monthly reports of air quality monitoring to the Division. These monthly reports will include descriptions of activities that occurred during the monitoring period such that monitoring data can be understood in relation to activity onsite (e.g., accounting for engine emissions). The Commission recognizes that monitoring data often requires additional analysis to interpret the resulting data. Therefore, for this first oil and gas air quality monitoring program, the Commission expects that operators will make the raw data (e.g., monitor/sensor and meteorological readings prior to analysis or processing) available to the Division upon request (and expects the Division to make the raw data available to the relevant local government entities upon request) but submit the analyzed data results in the monthly reports. The Commission believes these reports will provide valuable information to interested citizens, particularly those who live in close proximity to oil and gas facilities. Therefore, the Commission requests that the Division make the reports publicly available in the most efficient means possible, which may include posting on the Division's website individual reports and/or a compilation summary. This flexible monitoring program is intended as an initial step to help inform future oil and gas monitoring efforts.

Recognizing that this pre-production emissions monitoring program represents a first step in understanding both pre-production emissions and the rapidly evolving technologies that may be used to monitor them, the Commission directs the Division to report back to the Commission no later than March 31, 2022 with an initial summary of activities to implement the rule since September, 2020; learnings and insights on monitoring technologies, including technologies for continuous methane monitoring; appropriate data summaries on observed emissions based on the monthly reports received; initial feedback on the adequate length of monitoring time during and possible identification of exemptions from monitoring for certain types of facilities.

Flowback vessels

The Commission also adopted in the new Section VI. a requirement for owners or operators of pre-production operations to control emissions from flowback vessels. After hydraulic fracturing, operators bring the frac fluids and entrained solids to the surface. EPA's NSPS OOOOa Section 60.5375a requires operators to route flowback during the initial flowback stage into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. During the separation flowback stage, NSPS OOOOa requires operators to route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the liquids into a well, or route the liquids to a collection system. NSPS OOOOa allows operators to use open vessels to contain flowback fluids and solids and does not consider a well completion vessel a storage vessel, which means operators are not required to control well completion vessel emissions. Therefore, to build on the NSPS reduced emission completion requirements and further reduce pre-production tank emissions, owners or operators of pre-production operations must use enclosed flowback vessels after the drill-out phase, which the Commission recognizes has a high ratio of solids to liquids, and route emissions from flowback vessels to air pollution control equipment.

Class II disposal well facilities

The Commission added a new definition of class II disposal well facilities. This definition is based on EPA's Underground Injection Control Program: Criteria and Standard definition of class II well (see 40 CFR Section 146.5(b)(1)). The Commission did not include the element of EPA's definition concerning enhanced recovery of oil or natural gas as storage tanks related to those activities are considered part of the associated well production facility. The Commission recognizes that some class II disposal well facility operators interpret Part D, Section II.C. such that their storage tanks have not been subject to the storage tank control requirements. Although the Commission understands that the Division intended Part D, Section II.C. to apply to storage tanks serving class II disposal well facilities, the Commission also recognizes that a good faith argument existed under the prior rule language to support the alternative interpretation. The Commission intends for the Division to work with owners or operators to address implementation concerns that may arise including related to the May 1, 2021, state-wide compliance deadline for controlling emissions from storage tanks ≥ 2 tpy and associated monitoring requirements as well as concerns related to the need for supplemental fuel to control emissions.

The Commission also expanded the hydrocarbon liquids loadout requirements in Part D, Section II.5. to hydrocarbon liquids loadout at class II disposal well facilities. Operators inject fluids, primarily brines, associated with oil and natural gas production into class II wells. Current regulatory requirements in the Safe Drinking Water Act for class II wells relate to the construction, operation, and monitoring of the well. The Safe Drinking Water Act does not require emissions reporting or storage tank or loadout emissions controls at class II disposal well facilities. Therefore, the Commission expanded the hydrocarbon liquids loadout requirements to class II disposal well facilities to reduce emissions from these operations.

The Commission directs the division to evaluate potential emission issues associated with load ins at class II disposal facilities

Annual emissions reporting

In 2019, the Commission adopted annual emissions reporting requirements for Colorado's oil and gas sector in Part D, Sections II.G., IV., and V. Owners and operators are required to report VOC, NOx, CO, ethane, and methane emissions to the Division on an annual basis. To further address and inform the GHG directives of Senate Bill 19-096 and House Bill 19-1261, the Commission expanded the reporting requirements to include the reporting of CO₂ and N₂O emissions from Colorado's oil and gas sector.

As described above, the Safe Drinking Water Act does not require emissions reporting. Therefore, the Commission also clarified and expanded the annual emissions reporting requirements for class II disposal well facilities to better understand the emissions from these facilities and activities. Related to the fluids accepted for injection disposal, the Commission is requiring owners or operators to take periodic samples of the liquids to inform emission estimates. Acknowledging that fluid intake and facility designs may differ, the Commission expects the Division will work with owners and operators to develop sampling frequencies and protocols and to ensure accurate and consistent methods are used for emissions estimation and reporting.

Further, these revisions will correct any typographical, grammatical, and formatting errors found within the regulation.

Incorporation by Reference

Section 24-4-103(12.5) of the State Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of Section 24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission includes reference dates to rules and reference methods incorporated in Regulation Number 7.

Community Engagement

Section 25-7-105(e) requires engagement with disproportionately impacted communities, other state agencies, stakeholders, and the public. The Division provided multiple ways for the public, local governments, industry, environmental groups, and other stakeholders to provide comment during the development of the proposed rules, including email and remote stakeholder meeting participation.

Additional Considerations

The Clean Air Act does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the ozone NAAQS and Regional Haze Rule and requires Colorado to attain the NAAQS and reduce visibility. Therefore, the Commission adopted certain revisions to Regulation Number 7 to reduce VOC and NOx emissions in Colorado.

In accordance with Sections 25-7-105.1 and 25-7-133(3), CRS, the Commission states the rules adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time.

These revisions do not exceed or differ from the federal act due to state flexibility in determining what control strategies to implement to reduce emissions. However, where the proposal may differ from federal rules under the federal act, in accordance with Section 25-7-110.5(5)(b), C.R.S., the Commission determines:

- (I) The revisions to Regulation Number 7 address equipment and operations in the oil and gas sector including engines, pre-production operations, and class II disposal well facilities storage tanks and storage tank loadout. The proposed revisions also revise the annual oil and gas sector emissions inventory report to include GHGs and class II disposal well facilities. NSPS JJJJ, NSPS OOOO, NSPS OOOOa, NSPS Kb, NSPS KKK, NESHAP HH, NESHAP HHH, NESHAP ZZZZ, and the Greenhouse Gas Reporting Program (GHGRP) in 40 CFR Part 98 may also apply to such oil and gas facilities and operations. The revisions to Regulation Number 7 apply on a broader basis to more storage tanks than the NSPS and NESHAP, more engines than NESHAP JJJJ, and more facilities and operations than the GHGRP.

- (II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies or work practices to comply. EPA has provided some flexibility in NSPS OOOO and NSPS OOOOa by allowing a storage vessel to avoid being subject to NSPS OOOO if the storage vessel is subject to any state, federal, or local requirement that brings the storage vessel's emissions below the NSPS OOOO threshold.
- (III) The CAA establishes the 8-hour ozone NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. The Regional Haze Rule was also not determined taking into account concerns unique to Colorado. Similarly, EPA develops NSPS or NESHAP considering national information and data, not Colorado specific issues or concerns.
- (IV) In addition to the 2008 ozone NAAQS, Colorado must also comply with the lower 2015 ozone NAAQS. And, Colorado must improve visibility in accordance with Regional Haze. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional analyses for the more stringent NAAQS. The current revisions also attempt to maintain the air quality in areas of Colorado currently attaining the NAAQS; should an area slide into nonattainment, a nonattainment area designation would likely result in the imposition of costlier retrofits. And, the current revisions will improve visibility across the state, in particular in Colorado's class I areas.
- (V) Colorado must attain the 2008 ozone NAAQS by July 20, 2021, and the 2015 ozone NAAQS by August 3, 2021, or risk being reclassified. Colorado must make reasonable progress toward improving visibility or risk EPA establishing a federal regional haze plan for Colorado. EPA has established a Serious SIP-RACT implementation deadline of July 20, 2021, for strategies not needed for any attainment demonstration. EPA has established a Regional Haze SIP submittal deadline of July 1, 2021. There is no timing issue that might justify changing the time frame for implementation of federal requirements.
- (VI) The revisions to Regulation Number 7 address emissions from engines and the oil and gas sector in a cost-effective manner, as detailed in the Economic Impact Analysis, allowing for continued growth of Colorado's industry.
- (VII) The revisions to Regulation Number 7 establish reasonable equity for owners and operators subject to these rules by providing the same standards for similarly situated and sized sources.
- (VIII) If Colorado continues to fail to achieve the NAAQS or make progress to reduce visibility, EPA may promulgate Federal Implementation Plans; thus potentially determining requirements for Colorado's sources. This outcome may subject others to increased costs.

- (IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements. The revisions to Regulation Number 7 establishing and revising annual oil and gas inventory reporting are different than EPA's GHGRP in that more sources will be required to report under Regulation Number 7. This is necessary for Colorado to better understand the oil and gas emission sources and the opportunities to pursue additional emission reductions. Newly enacted legislation in Colorado has also established a compelling reason to adopt the monitoring, recordkeeping, and reporting requirements in the revisions.
- (X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for hydrocarbon liquid loadout. Other revisions reflect changes in industry practice, such as for controlling emissions from flowback vessels.
- (XI) The revisions adopted will reduce NO_x, VOC, and methane, addressing both Colorado's ozone problems, making strides to reduce the impact of climate change, and making progress to improve visibility. As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will reduce emissions in a cost-effective manner.
- (XII) Alternative rules could also provide reductions in greenhouse gases, ozone, VOC, NO_x, other hydrocarbons, impacts to visibility, and nitrogen deposition to address Regional Haze, SB 19-181, and help to attain the NAAQS. SB 19-181 specifically directs the Commission to "consider" revising its rules to adopt more stringent requirements for the oil and gas sector. The Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in the need for much more stringent requirements to reduce nitrogen deposition in RMNP, improve visibility in Colorado's Class I areas, and reduce ozone across the state but particularly in the DMNFR.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in CRS Section 25-7-109(1)(b).

To the extent that CRS Section 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

- (I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.
- (II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of methane, VOCs, and other hydrocarbons.
- (III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.
- (IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.
- (V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

U. December 17-18, 2020 (Part D, Section II.; Part E, Sections II., IV., and V.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the State Administrative Procedure Act, § 24-4-103(4), C.R.S., the Colorado Air Pollution Prevention and Control Act, §§ 25-7-101, C.R.S., et. seq., and the Air Quality Control Commission's (Commission) Procedural Rules, 5 Code Colo. Reg. §1001-1.

Basis

On December 26, 2019, the Environmental Protection Agency (EPA) reclassified the Denver Metro North Front Range (DMNFR) to Serious, after 2015-2017 ozone data failed to show attainment of the 2008 8-hour Ozone National Ambient Air Quality Standard (NAAQS). See 84 Fed. Reg. 247 (December 26, 2019). As a Serious area, the major source threshold lowers from 100 tons per year (tpy) of VOC or NOx to 50 tpy. EPA has also designated the DMNFR as Marginal nonattainment for the 2015 ozone NAAQS of 70 ppb.

Therefore, to ensure progress towards attainment of the 2008 and 2015 ozone NAAQS, the Commission is adopting revisions to Regulation Number 7 to include reasonably available control requirements (RACT) for major sources with VOC and/or NOx emissions equal to or greater than 50 tpy; specifically, for foam manufacturing, boilers, turbines, landfill gas and biogas fired engines, and wood surface coating.

Statutory Authority

The State Air Act, specifically § 25-7-105(1), directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in § 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere (and, as such, includes VOC, NOx, methane and other hydrocarbons) and provides the Commission broad authority to regulate air pollutants.

Section 105(1)(a)(I) directs the Commission to adopt a state implementation plan (SIP) to attain the NAAQS. Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution. Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Sections 25-7-109(1)(a), (2), and (3) of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons. Section 25-7-109(10) directs the Commission to adopt emission control regulations to minimize emissions of methane, other hydrocarbons, VOC, and NOx from oil and gas operations.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 7, and includes technological and scientific rational for the adoption of the revisions.

The Commission is revising Regulation Number 7 to include provisions in the SIP that require the implementation of RACT for major sources ($\geq$ 50 tpy NOx and/or VOC) including expanding existing requirements, incorporating federal requirements, and including categorical RACT requirements.

The Commission is also clarifying requirements related to leak detection and repair (LDAR) inspections. The revisions also correct typographical, grammatical, and formatting errors found through the regulation.

Major source RACT

Due to the reclassification to Serious, Colorado must submit revisions to its SIP to address the Clean Air Act's (CAA) Serious ozone nonattainment area requirements, as set forth in CAA §§ 172 and 182(c) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (See 80 Fed. Reg. 12264 (March 6, 2015)). A Serious SIP revision must include provisions that require the implementation of RACT for major sources of VOC and/or NOx (i.e., sources that emit or have the potential to emit 50 tpy or more) and for each category of VOC sources covered by a Control Technique Guideline (CTG) for which Colorado has sources in the DMNFR.

Therefore, the Commission adopted revisions to Regulation Number 7 to include RACT requirements in Colorado's ozone SIP for 50 tpy major sources of VOC and/or NOx including a NOx emission limit for boilers between 50 MMBtu/hr and 100 MMBtu/hr, a NOx emission limit for landfill gas or biogas fired engines, NOx emission limits for combustion turbines, categorical requirements to reduce VOC emissions related to foam manufacturing, and expanded categorical requirements to reduce VOC emissions related to wood surface coating.

Boilers

In 2019, the Commission expanded the combustion equipment requirements adopted in 2016 and 2018 for the 100 tpy major sources to the 50 tpy major sources. Specifically, for boilers, the Commission adopted provisions requiring boilers greater than or equal to 50 MMBtu/hr at 50 tpy major sources to comply with a 0.2 lb/MMBtu NOx emission limit. The Commission now further expands the categorical RACT requirements to require 50-100 MMBtu/hr boilers at 50 tpy major sources to comply with a 0.1 lb/MMBtu NOx emission limits. The owners or operators of these boilers will continue to comply with the combustion process adjustment, periodic performance testing, and recordkeeping requirements.

Engines

In 2019, the Commission expanded the NOx emission limit requirements for compression ignition reciprocating internal combustion engines (RICE) and combustion process adjustment requirements for stationary RICE. The Commission now further expands the categorical RACT requirements for engines to include landfill gas and biogas fired RICE and require the engines to comply with the NOx emission limit in EPA's NSPS JJJJ for landfill/digester gas fired engines. The owners or operators of these engines will continue to comply with the combustion process adjustment, periodic performance testing, and recordkeeping requirements.

Turbines

In 2019, the Commission adopted provisions requiring turbines constructed before February 18, 2005, to comply with NSPS GG and turbines construction after February 18, 2005, to comply with NSPS KKKK. During review of the submitted SIP RACT requirements, EPA questioned Colorado's reliance on EPA's NSPS GG as RACT and requested Colorado consider the NOx emission limits in EPA's NSPS KKKK for Colorado's NSPS GG and pre-NSPS GG turbines at major sources. While the Commission does not agree that NSPS GG is inappropriate as SIP RACT for Colorado's NSPS GG and pre-NSPS GG turbines, the Commission revised the requirements for turbines to reference NSPS KKKK NOx emission limits for the turbines constructed before February 18, 2005, but retain the testing and monitoring requirements of NSPS GG. Turbines with CEMS that are capable of operating in both combined and simple cycle modes are to show compliance with a 30-day average. Similar to EPA's discussion in the preamble to NSPS KKKK, the Commission recognizes turbines may have emission spikes during unit startup and that, therefore intends the turbine NOx emission limits to be implemented as under NSPS KKKK. See 71 Fed. Reg. 38,482 at 38,488-38,489 (July 6, 2006) "While continuous compliance is not required, excess emissions during startup, shutdown, and malfunction must be reported." All turbines will continue to comply with good air practices for minimizing emissions, combustion process adjustment, and recordkeeping requirements.

Wood coating

In 2018, the Commission adopted requirements for wood furniture surface coating based on recommendations in EPA's Control of Volatile Organic Compound Emissions from Wood Furniture Manufacturing Operations CTG (Wood Furniture CTG) (1996), including topcoat and sealer VOC content limits, work practices, and recordkeeping requirements. Wood furniture is defined to mean "any product made of wood, a wood product such as rattan or wicker, or an engineered wood product such as particleboard," which is not inclusive of all wood products such as doors. However, in EPA's A Guide to the Wood Furniture CTG and NESHAP (1997), EPA states that "States may choose to extend their rules to other operations. For example, some States have developed rules for manufacturers of wood products so they may include limitations for manufacturers of items such as musical instruments or doors." Therefore, the Commission expanded the wood furniture surface coating requirements to the surface coating of other wood products such as doors, door casings, and decorative wood accents.

Foam manufacturing

The Commission adopted new VOC control requirements for foam manufacturing operations. The new provisions affect three foam manufacturing operations, although one of the sources is modifying their permit to more accurately reflect their actual emissions and will, therefore, have VOC emissions below 50 tpy. These new provisions include emission control requirements, work practices, monitoring, and recordkeeping requirements for foam manufacturing operations.

LDAR (Part D, Section II.)

The Commission also adopted clarifying revisions to the leak detection and repair (LDAR) provisions the Commission adopted in December 2019 including clarification to applicability and requirements for recordkeeping and reporting. The clarifications to Sections II.E.4.c. and II.E.4.d. ensure that operators continue to determine applicability in accordance with the storage tank or facility emissions as they have since the LDAR program was adopted in 2014. The inclusion of recordkeeping and reporting elements specific to increased inspections based on location from occupied areas ensure that the Commission can evaluate the efficacy of the LDAR program. The Commission acknowledges that not all operators will need to conduct a precise analysis concerning their location in relation to occupied areas (i.e., proximity analysis) based on their general distance. However, the Commission believes it is important for operators to provide at least general documentation that they considered their location, even if to describe an extreme remote location. The Commission also acknowledges that some operators may elect to comply with the increased frequency inspections for certain facilities without conducting a proximity analysis. Documentation of this decision to comply with the increased inspection frequency satisfies the proximity analysis requirement.

The Local Community Organizations proposed an alternate rule to establish shorter repair deadlines for leaks discovered at well production facilities within 1,000 feet of an occupied area. The Local Community Organizations, industry, and the Division negotiated and agreed to the final language adopted by the Commission. For leaks identified at a well production facility located within 1,000 feet of an occupied area, operators must make a first attempt to repair the leak as soon as practicable, but no later than five working days after discovery of the leak. If repair cannot be completed within five days and the leak is not stopped using other means, the owner or operator must notify the local government with jurisdiction over the location and the Division. Reasons why an operator may be unable to attempt or complete repair within five days include, among other things, inclement weather that prevents a timely repair or repair attempt or delays in procuring necessary heavy equipment and workover rigs. The industry parties also raised the issue about local government or other agency requirements potentially delaying repair. Such impacts to repair schedules should be considered as the program is implemented.

The Commission notes that it will be the operator's responsibility to demonstrate the need for the delay beyond five working days, and the Commission expects that operators will be able to explain the types of reasonable efforts the operator undertakes to avoid the delay (e.g., reasonable efforts in procuring the equipment). If a leak is detected at a facility without a proximity analysis, operators may conduct a proximity analysis and may follow the repair deadlines in Section II.E.7.a. if there are no occupied areas within 1,000 feet.

Consistent with the existing LDAR program, leaks detected are not subject to enforcement by the Division so long as the operator complies with the repair and recordkeeping requirements of Section II.E. However, as the Commission noted in 2014 and again in 2017, the Commission does not intend to relieve owners or operators of the obligation to comply with the general requirements of Part D, Sections I.C, II.B, or II.C (as applicable), including the requirements to minimize emissions and to operate without venting.

Further, these revisions will correct any typographical, grammatical, and formatting errors found within the regulation.

Incorporation by Reference

Section 24-4-103(12.5) of the State Administrative Procedure Act allows the Commission to incorporate by reference federal regulations. The criteria of §24-4-103(12.5) are met by including specific information and making the regulations available because repeating the full text of each of the federal regulations incorporated would be unduly cumbersome and inexpedient. To fully comply with these criteria, the Commission included reference dates to rules and reference methods incorporated in Regulation Number 7, Part E, Section II.

Additional Considerations

Colorado must revise Colorado's ozone SIP to address the serious ozone nonattainment area requirements. The CAA does not expressly address all of the provisions adopted by the Commission. Rather, federal law establishes the ozone NAAQS and requires Colorado to develop a SIP adequate to attain the NAAQS. Therefore, the Commission adopted certain revisions to Regulation Number 7 to satisfy Colorado's serious nonattainment area obligations.

The Commission also adopted revisions to Regulation Number 7 to achieve further emission reductions in the oil and gas sector.

In accordance with §§ 25-7-105.1 and 25-7-133(3), CRS, the Commission states the rules in Part D, Section II. of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time.

These revisions do not exceed or differ from the federal act due to state flexibility in determining what control strategies to implement to reduce emissions. However, where the proposal may differ from federal rules under the federal act, in accordance with § 25-7-110.5(5)(b), CRS, the Commission determines

- (I) The revisions to Regulation Number 7 address equipment and operations in the oil and gas sector including fugitive emissions from components. NSPS OOOO and NSPS OOOOa may also apply to such oil and gas facilities and operations. The revisions to Regulation Number 7 apply on a broader basis to more fugitive emissions components than the NSPS.

The Commission revised Regulation Number 7 to include regulatory RACT requirements for Colorado's major sources of VOC and/or NO_x (≥ 50 tpy) in the SIP. Specifically, the Commission revised Regulation Number 7, Part B, Section I. and Part E, Sections II. and V. to include categorical regulatory RACT requirements. MACT DDDDD, MACT JJJJJJ, MACT ZZZZ, MACT YYYY, NSPS GG, NSPS KKKK, NSPS IIII, and NSPS JJJJ may apply to such combustion equipment. However, the Regulation Number 7 revisions apply on a broader basis to more combustion equipment.

- (II) The federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies or work practices to comply. EPA has provided some flexibility in NSPS OOOOa by allowing a company to apply to EPA for an alternative means of emission limitations for fugitive emissions components.
- (III) The CAA establishes the 2008 NAAQS and requires Colorado to develop SIP revisions that will ensure attainment of the NAAQS. The ozone NAAQS was not determined taking into account concerns unique to Colorado. Similarly, EPA develops NSPS or NESHAP considering national information and data, not Colorado specific issues or concerns. In addition, Colorado cannot rely exclusively on a federally enforceable permit or federally enforceable NSPS or NESHAP to satisfy Colorado's Moderate nonattainment area RACT obligations. Instead, Colorado can adopt applicable provisions into its SIP directly, as the Commission has done here.
- (IV) In addition to the 2008 NAAQS, Colorado must also comply with the lower 2015 ozone NAAQS. These current revisions may improve the ability of the regulated community to comply with new requirements needed to attain the lower NAAQS insofar as RACT analyses and efforts conducted to support the revisions adopted by the Commission may prevent or reduce the need to conduct additional RACT analyses for the more stringent NAAQS.
- (V) EPA has established a Serious SIP-RACT implementation deadline of July 20, 2021, for strategies not needed for any attainment demonstration. There is no timing issue that might justify changing the time frame for implementation of federal requirements.
- (VI) The revisions to Regulation Number 7 strengthen Colorado's SIP and state-only provisions. These sections currently address emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry. The revisions to Regulation Number 7, Part C, Sections I. recognize practices currently utilized by wood coating operations. The revisions to Regulation Number 7, Part E, also consider specific existing major sources of VOC and NO_x, allowing for continued growth at Colorado's major sources.
- (VII) The revisions to Regulation Number 7 Part D establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources. The revisions to Regulation Number 7, Part C and Part E similarly establish the categorical RACT requirements for similarly situated and sized sources.
- (VIII) If EPA does not approve Colorado's SIP, EPA may promulgate a Federal Implementation Plan; thus potentially determining RACT for Colorado's sources. This outcome may subject others to increased costs.
- (IX) Where necessary, the revisions to Regulation Number 7 include minimal monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.

- (X) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for component leaks. Other revisions reflect changes in industry practice, such as for wood coating and foam manufacturing. Similarly, the revisions concerning major sources of VOC and NOx generally reflect current emission controls and work practices.
- (XI) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will reduce emissions in a cost-effective manner.
- (XII) Alternative rules could also provide reductions in ozone, VOC, NOx, methane, and other hydrocarbons to address SB 19-181 and help to attain the NAAQS. The Commission determined that the Division's proposal was reasonable and cost-effective. However, a no action alternative would very likely result in an unapprovable SIP.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in CRS § 25-7-109(1)(b).

Colorado must revise Colorado's ozone SIP to address the serious nonattainment area requirements. However, to the extent that CRS § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

- (I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.
- (II) Evidence in the record supports the finding that the rules shall result in a demonstrable reduction of methane, VOCs, and other hydrocarbons.
- (III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.
- (IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.
- (V) The rule will maximize the air quality benefits of regulation in the most cost-effective manner.

V. February 18, 2021 (Part D, Section III.)

This Statement of Basis, Specific Statutory Authority, and Purpose complies with the requirements of the State Administrative Procedure Act, § 24-4-103(4), C.R.S., the Colorado Air Pollution Prevention and Control Act, §§ 25-7-101, C.R.S., et. seq., and the Air Quality Control Commission's (Commission) Procedural Rules, 5 Code Colo. Reg. §1001-1.

Basis

During the 2019 legislative session, Colorado's General Assembly adopted revisions to several Colorado Revised Statutes in Senate Bill 19-181 (SB 19-181) (Concerning additional public welfare protections regarding the conduct of oil and gas operations) that include directives for the Commission. SB 19-181 revised the Air Quality Control Commission's directives in § 25-7-109, CRS, to consider pneumatic device requirements. Additionally, in HB 19-1261, the legislature mandated a 26% reduction in GHG by 2025, 50% by 2030, and 90% by 2050 (from a 2005 baseline), §§ 25-7-102(2)(g), 25-7-105(1)(e)(II), CRS.

Further, on December 26, 2019, the Environmental Protection Agency (EPA) reclassified the Denver Metro North Front Range (DMNFR) to Serious, after 2015-2017 ozone data failed to show attainment of the 2008 8-hour Ozone National Ambient Air Quality Standard (NAAQS). See 84 Fed. Reg. 247 (December 26, 2019). As a Serious area, the major source threshold lowers from 100 tons per year (tpy) of VOC or NO_x to 50 tpy. EPA has also designated the DMNFR as Marginal nonattainment for the 2015 ozone NAAQS of 70 ppb.

Therefore, to further minimize emissions from the oil and gas sector and ensure progress towards attainment of the 2008 and 2015 ozone NAAQS and necessary greenhouse gas emission reductions, the Commission is adopting revisions to Regulation Number 7 to require non-emitting controllers in certain situations.

Statutory Authority

The Colorado Air Pollution Prevention and Control Act, specifically § 25-7-105(1), directs the Commission to promulgate such rules and regulations as are consistent with the legislative declaration set forth in § 25-7-102 and that are necessary for the proper implementation and administration of Article 7. The Act broadly defines air pollutant to include essentially any gas emitted into the atmosphere (and, as such, includes VOC, NO_x, methane and other hydrocarbons) and provides the Commission broad authority to regulate air pollutants.

Section 25-7-106 provides the Commission maximum flexibility in developing an effective air quality program and promulgating such combination of regulations as may be necessary or desirable to carry out that program. Section 25-7-106 also authorizes the Commission to promulgate emission control regulations applicable to the entire state, specified areas or zones, or a specified class of pollution.

Section 25-7-106(6) further authorizes the Commission to require owners and operators of any air pollution source to monitor, record, and report information. Sections 25-7-109(1)(a), (2), and of the Act authorize the Commission to promulgate regulations requiring effective and practical air pollution controls for significant sources and categories of sources, emission control regulations pertaining to nitrogen oxides and hydrocarbons, and emissions control regulations pertaining to the storage and transfer of petroleum products and other VOCs. Section 25-7-109(2)(c), in particular, provides broad authority to regulate hydrocarbons. Section 25-7-109(10) directs the Commission to adopt emission control regulations to minimize emissions of methane, other hydrocarbons, VOC, and NO_x from oil and gas operations.

Purpose

The following section sets forth the Commission's purpose in adopting the revisions to Regulation Number 7 and includes the technological and scientific rationale for the adoption of the revisions. The revisions also correct typographical, grammatical, and formatting errors found through the regulation. As discussed, SB 19-181 identifies specific requirements the Air Quality Control Commission should consider, including pneumatic controller requirements.

In December 2019, the Commission expanded the pneumatic controller inspection and maintenance requirements, adopted in 2017, from nonattainment area applicability to statewide applicability. As part of that rulemaking, the Commission directed the Statewide Hydrocarbon Emission Reduction (SHER) team and Pneumatic Controller Task Force (PCTF), stakeholder processes directed by the Commission in 2017, to continue their stakeholder processes and bring to the Commission in 2020 their recommendations on the use of zero-bleed pneumatic devices. Both the SHER team and PCTF continued to meet through the spring of 2020. The stakeholder discussions from 2017-2020 informed the Commission's adopted provisions regarding non-emitting controllers. Non-emitting controllers are a broader category than no-bleed pneumatic controllers and can include, but are not limited to, air-driven controllers, mechanical controllers, electric controllers, self-contained controllers and controllers where exhaust gas is routed to a combustion device.

Definitions

The Commission took the opportunity to amend the definitions associated with pneumatic controllers to reflect more accurate and appropriate technical definitions. The definition of “intermittent pneumatic controller” is intended to include controllers that are not designed to have a continuous bleed rate. Although intermittent pneumatic controllers are not designed to emit between actuations, de minimis emissions may occur between actuations. Such de minimis emissions do not alter a controller’s classification as “intermittent.”

New Facilities and Certain Retrofits

The revisions to Regulation Number 7 adopted in this rulemaking require the use of non-emitting controllers at well production facilities and natural gas compressor stations that commence operations on or after May 1, 2021. The revisions also require retrofits of natural gas emitting pneumatic controllers to non-emitting controllers at well production facilities where a well first begins production or is recompleted or refractured on or after May 1, 2021 and at natural gas compressor stations that increase horsepower on or after May 1, 2021.

Company-wide plans

Additionally, the Commission has required operators with well production facilities or natural gas compressor stations that commenced operations prior to May 1, 2021 to develop plans on a company-wide basis to convert some of such facilities to use non-emitting controllers. For purposes of Section III.C.4, retrofit refers to converting a natural gas emitting pneumatic controller to a non-emitting controller. Plugging and abandoning an existing well production facility constitutes an alternative method of compliance with retrofit requirements as described in Section III.C.4.c.(iii). Specifically, the Commission has adopted a program that requires owners or operators of well production facilities that commenced operations prior to May 1, 2021 to determine the percentage of their total liquids production at facilities with non-emitting controllers. Facilities that commenced operation prior to May 1, 2021 shall be included in the relevant (well production or compressor station) companywide plan, and the companywide plan shall reflect operations as of May 1, 2021. If any of the events described in Sections III.C.4.a.(ii) or (iii) occur on or after May 1, 2021 and before May 1, 2023, then the owner or operator may count, as applicable, the: (1) percentage of production allocated to that facility as of May 1, 2021 as retrofit for purposes of the well production facility companywide plan; or (2) the pneumatic controllers emitting to atmosphere as of May 1, 2021 as retrofit for purposes of the compressor station companywide plan. Where facility production must be estimated pursuant to Section III.C.4.c.(ii)(A)(3), owners or operators will follow the same process that would be used to establish permit limitations on production throughput, such as summation of anticipated production curves. Of note, if a facility operating in 2019 was subsequently acquired by a new operator, then the facility (and its percent of production) is associated with the company-wide plan of the entity owning the facility as of May 1, 2021.

Based upon this percentage, operators will be required to retrofit facilities incrementally by May 1, 2022 and May 1 2023; the required retrofits correspond to an increasing percentage of each operator’s total liquids production flowing through facilities with non-emitting controllers. The incremental percentage increases for well production facilities are found in Table 1. Operators that increase their total non-emitting facility percent production up to a specified threshold are not required to achieve the entire incremental percentage increase that would otherwise apply for that year. However, the minimum incremental increases and specified thresholds do not restrict operators from exceeding the requirements.

Each well production facility operator is required to submit a company-wide plan by September 1, 2021 that lists specific information regarding its facilities that commenced operations prior to May 1, 2021, its total liquids production, facilities with non-emitting controllers, total percentage of liquid production flowing through facilities with non-emitting controllers, and the facilities that the operator intends to retrofit or plug and abandon in order to achieve the incremental increases in total liquids production flowing through facilities with non-emitting controllers. This company-wide plan should be updated in July 2022, with a final company-wide plan reflecting all facilities that were retrofit or plugged and abandoned submitted in July 2023.

The Commission has also required operators of natural gas compressor stations that commenced operations prior to May 1, 2021 to develop plans on a company-wide basis to convert pneumatic controllers at such facilities to non-emitting controllers. Specifically, the Commission has adopted a program that requires operators to determine the percentage of emitting and non-emitting pneumatic controllers and based upon that percentage, operators will be required to increase the percentage of non-emitting controllers incrementally by May 1, 2022 and May 1, 2023. The incremental percentage requirements for natural gas compressor stations are found in Table 2. As for well production facilities, operators that increase their total percentage of non-emitting controllers up to a specified threshold are not required to achieve the entire percentage increase for that year that would otherwise apply. The minimum percentage increases and specified thresholds do not restrict operators from exceeding these requirements.

Each operator is required to submit a company-wide plan by September 1, 2021 that lists specific information regarding its facilities that commenced operations prior to May 1, 2021, total controllers, percentage of emitting and non-emitting controllers, the required incremental increases in non-emitting controllers, and the pneumatic controllers that the operator intends to retrofit or remove from service to achieve the incremental increases in non-emitting controllers.

For well production facilities and natural gas compressor stations, an owner or operator may elect to combine facilities with other owners or operators that are owned or operated by the same parent company in complying with company-wide compliance plan requirements.

At this time, operators will not be subject to the requirement to retrofit pneumatic controllers if they have facilities that on a company-wide basis, and taking into account only wells that produced oil or gas or both in calendar year 2019, averaged 15 barrels of oil and gas equivalent ("BOE") or less per day per well. However, in 2021, the Commission plans to consider additional emission reductions for the oil and gas sector that would enable the state to meet its ambitious climate goals as set forth in HB 19-1261. The Commission directs the Division to consider whether additional requirements to reduce emissions at the sites not subject to retrofit pursuant to Section III.C.4.c.(iv), including retrofit of pneumatic controllers, should be included in that rulemaking.

The requirement to submit an acknowledgement or certification under Sections III.C.4.c.(v) and III.C.4.d.(v) (regarding sale or transfer) does not apply to well production facilities or natural gas compressor stations that, at the time of sale or transfer are not intended to and will not be used to achieve the Total Required Non-Emitting Facility Percent Production or Total Required Non-Emitting Percent Controller target, as applicable. The following are each an acceptable means of ensuring compliance with Section III. following transfer through which owners or operators shall satisfy their obligations under Section III.C.4.c.(v) or Section III.C.4.d.(v), as applicable:

Example 1: Operator A has a Total Historic Non-Emitting Facility Percent Production of 61%. Operator A is required to achieve an additional 5% of non-emitting facility percent production by May 1, 2022, and an additional 10% by May 1, 2023, with a Total Required Non-Emitting Facility Percent Production target of 76%. Operator A achieves the additional 5% of non-emitting facility percent production by May 1, 2022. In 2023, prior to May 1, Operator A transfers ownership to Operator B of two well production facilities that Operator A had intended to retrofit with non-emitting controllers or plug and abandon in order to achieve its Total Required Non-Emitting Facility Percent Production. Retrofitting or plugging and abandoning those two facilities would have comprised half of the additional production required by May 1, 2023 (*i.e.*, 5% of Total Required Non-Emitting Facility Percent Production).

Scenario 1: Notwithstanding the transfer, Operator A may find an alternative 5% of Total Historic Production remaining in its Company-Wide Plan to achieve its Total Required Non-Emitting Facility Percent Production. In this case, Operator A does not need to submit an acknowledgement or certification upon transfer, but shall include this information in its next update to the Company-Wide Plan. This example would apply equally to transfers of assets subject to a Company-Wide Compressor Station Pneumatic Controller Compliance Plan.

Scenario 2: Operator A submits an acknowledgement, on a Division-approved form, that it will ensure the transferred asset is retrofit by May 1, 2023. Under this scenario, either Operator A or Operator B may undertake any necessary retrofitting (or plugging and abandonment) of the asset to allow Operator A to take credit for retrofit of the 5% of Total Historic Production, provided, however, that Operator A will remain responsible for retrofit of that asset to achieve its Total Required Non-Emitting Facility Percent Production. This means that if retrofit of the asset is not completed for whatever reason, Operator A would have to find an alternative 5% of Total Historic Production remaining in its Company-Wide Plan to achieve its Total Required Non-Emitting Facility Percent Production by May 1, 2023.

Scenario 3: Operator A submits an acknowledgement, on a Division-approved form, that it plans to use the transferred asset to achieve its Total Required Non-Emitting Facility Percent Production and Operator B certifies, on a Division-approved form, that it will retrofit the transferred asset by May 1, 2023. Upon certification by Operator B, Operator A shall receive credit for the retrofit of the 5% of Total Historic Production towards its applicable targets under Section III.C.4. The Division-approved form must include a statement that Operator B assumes Operator A's Section III.C.4 obligations with respect to the transferred asset and is, therefore, subject to the Division's enforcement authority in the event of noncompliance. Acquisition of the asset does not alter the calculation of Operator B's compliance with the percentage thresholds specified in Table 1 or 2 for its own Company-Wide Plan, if applicable.

Example 2: Operator A has a Total Historic Non-Emitting Facility Percent Production of 61% and a Total Required Non-Emitting Facility Percent Production target of 76%. Operator B has a Total Historic Non-Emitting Facility Percent of 21% and a Total Required Non-Emitting Facility Percent Production target of 56%. Operator A and Operator B merge (or one entity acquires the other) in 2023, prior to May 1. Despite the merger, the resulting ownership of Operators A and B must continue to separately comply with the respective Company-Wide Plans and Total Required Non-Emitting Facility Percent Production targets of Operator A and Operator B that existed prior to merger.

Exemptions for Specific Controllers

The Commission has recognized that there are appropriate circumstances where even non-emitting facilities may need to use pneumatic controllers that emit natural gas to the atmosphere.

Section III.C.4.e.(i)(A) authorizes use of pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas. Starting May 1, 2021, new well production facilities or facilities where a well first begins production or is recompleted or refractured, and new compressor stations or stations that increase horsepower, must submit a justification for any safety or process exemption to the Division for approval 45 days prior to installation of the emitting device or retrofit of the facility. Owners or operators that intend to rely on this exemption to maintain emitting controllers at facilities that are retrofit under a company-wide plan must submit a justification to the Division 45 days prior to retrofit of the facility. The Commission notes that the rule may not be effective 45 days prior to May 1, 2021. If so, for well production facilities and natural gas compressor stations commencing operation or taking actions described in Sections III.C.4.a.(ii) or (iii) on or after May 1, 2021 but prior to June 1, 2021, the owner or operator shall submit the justification required in Section III.C.4.e.(i)(A)(1) by May 1, 2021, and the justification shall be deemed approved unless denied prior to commencing operation or prior to the time the actions described in Sections III.C.4.a.(ii) or (iii) occur. Section III.C.4.e.(i)(A), the requirement to seek Division approval is not applicable for: (1) well production facilities that qualify as contributing to Historic Non-Emitting Facility Percent Production, as defined in Section III.C.4.c.(ii)(D)(1) to (2), or (2) compressor stations that commenced operation before May 1, 2021.

Section III.C.4.e.(i)(B) authorizes use of pneumatic controllers that emit natural gas for activities that occur prior to the end of flowback and well abandonment activities. In addition, Section III.C.4.e.(i)(C) allows owners or operators, upon notice to the Division, to use temporary and portable equipment with pneumatic controllers that emit natural gas for sixty days for purposes other than increasing the throughput of the facility. The Commission directs the Division to develop a streamlined mechanism for filing these notifications, including evaluating the potential for electronic notification. Owners or operators must request Division approval to extend the sixty-day timeframe and must do so at least fourteen days prior to the end of the exemption period. Owners or operators utilizing temporary or portable equipment with pneumatic controllers that emit natural gas must conduct AVO and AIMM inspections of those controllers on the same schedule as the associated well production facility or compressor station under Section II.E., and must comply with the repair, recordkeeping, and reporting requirements of Sections II.E.6 through 9.

The requirement to use non-emitting pneumatic controllers at sites that commenced operations on or after May 1, 2021, or where one or more wells first begin production or are recompleted or refractured on or after May 1, 2021 does not apply in certain applications at some wellheads located away from the associated production facilities. Additionally, operators that have or retrofit well production facilities to be non-emitting pursuant to the company-wide plan may not be required to use non-emitting controllers in certain applications at some wellheads located away from the associated production facilities.

As set forth in Section III.C.4.e.(i)(D), operators may use natural gas actuated pneumatic controllers that emit to the atmosphere to control emergency shutdown devices or artificial lift control at a wellhead if the wellhead is located more than one quarter of a mile from the associated well production facility for well production facilities commencing operations on or after May 1, 2021, or for wellheads not located on the same surface disturbance for well production facilities commencing operations prior to May 1, 2021. Any other pneumatic controllers (e.g. those not used as emergency shutdown devices or for artificial lift control) located at the wellheads within the specified distance from the associated production facilities must be non-emitting, unless the operator submits a justification for use of an emitting controller to the Division for approval at least 45 days prior to installation of the emitting device or retrofit of the facility or by July 1, 2021 for well production facilities that commenced operations prior to May 1, 2021 and the operator intends to be reflected as non-emitting in the company-wide plan. The Commission notes that the rule may not be effective 45 days prior to May 1, 2021. If so, for well production facilities commencing operation or taking actions described in Section III.C.4.a.(ii) on or after May 1, 2021 but prior to June 1, 2021, the owner or operator shall submit the justification required in Section III.C.4.e.(i)(D)(1) by May 1, 2021, and the justification shall be deemed approved unless denied prior to commencing operation or prior to the time the actions described in Section III.C.4.a.(ii) occur. The one quarter mile measurement associated with distance from the wellhead to the well production facility shall be measured from the wellhead to the closest equipment associated with the well production facility.

To qualify for the exemption in Section III.C.4.e.(i)(D), the operator must use an approved instrument monitoring method and AVO to detect leaks at the wellhead at the same frequency as the associated well production facility as set forth in Table 3 of Section II.E.4, which sets forth the frequency of component inspections, or no less than once per year, whichever is greater. For facilities that commenced operations prior to May 1, 2021, this monitoring requirement will begin on May 1, 2022, or the date the facility is converted to a site with only non-emitting controllers, whichever is later. The Commission recognizes that wellheads may sometimes be difficult to inspect due to land access issues or severe weather and has adopted provisions allowing operators to delay inspections until access is restored. Owners or operators also may utilize OGI camera-equipped aerial drones to perform these wellhead inspections to provide frequent leak detection and further promote the advancement of leak detection methodologies - both of which are foundational to Colorado's find and fix approach to leak detection. At the same time, the Commission believes this application of OGI requires rethinking of the methodology generally used for land based OGI applications.

Thus, the provisions of Section III.C.4.e.(i)(D)(3) allowing for the use of OGI camera-equipped aerial drones to inspect wellhead equipment apply on a limited basis, as state-only provisions and do not by themselves authorize the use of drones to inspect other equipment or constitute approval of drones as alternative AIMM. Operators must develop their own methodology before using OGI camera-equipped aerial drones and make that methodology available to the Division upon request. The methodology must include, at a minimum, procedures for: determining maximum wind speed during which the inspection can be performed; determining the maximum viewing distance from the equipment; how the operator will ensure an adequate thermal background is present to view potential leaks; how the operator will deal with adverse monitoring conditions, such as wind; and how the operator will deal with interferences. At a minimum, any drone inspection must ensure line of sight from the drone to all wellhead equipment and components and take place when the drone-mounted camera is close enough to the wellhead equipment and components to achieve sensitivity for detection of emissions similar to the sensitivity commonly achieved during OGI inspections carried out with hand-carried infrared cameras. Furthermore, the Commission directs the parties to this rulemaking that wish to participate to jointly recommend an OGI camera-equipped aerial drone usage methodology to the Division's Alternative AIMM Team by May 2022, for further review and consideration.

Finally, operators may not use this exemption where equipment with natural gas emitting pneumatic controllers other than the wellhead, such as a separator, is located at the wellhead site. Under those circumstances, emitting pneumatic controllers used for emergency shut down control may still qualify for the safety and process exemption under Section III.C.4.e.(i)(A) where the necessary conditions and approvals for that exemption are met.

Tagging of Controllers

In order to assist in ease of identification of pneumatic controllers that are authorized to emit natural gas to the atmosphere, the Commission has required operators to tag pneumatic controllers that are authorized to emit natural gas to the atmosphere pursuant to the specified exemptions in Section III.C.4.e.(i) at wellhead production facilities which are non-emitting and at natural gas compressor stations that have one or more non-emitting controllers. Natural gas compressor station operators must differentiate between emitting pneumatic controllers that are exempt under Section III.C.4.e.(i) and those that are not identified as non-emitting controllers in the company-wide plan and are, thus, not required to retrofit. The requirement to tag pneumatic controllers that emit natural gas pursuant to Sections III.C.4.e.(i)(A) through (D) does not apply at well production facilities that are not required to be non-emitting or elected to be non-emitting pursuant to the company-wide plan requirements. In each instance where the regulation references a requirement to use non-emitting controllers, such reference is limited by the exemptions allowing the use of pneumatic controllers to emit natural gas to atmosphere as set forth in the regulation.

Recordkeeping

Operators of well production facilities or natural gas compressor stations must keep the following records for five years, and make them available to the Division upon request: (1) Records of the date a well production facility completes retrofit or all wells flowing to the well production facility are plugged and abandoned, or the date the natural gas compressor station pneumatic controllers were retrofit or it is taken out of service, (2) If claiming an exemption for an emitting pneumatic controller, records for each controller demonstrating the exemption applies, (3) Copies of the Company-Wide Well Production Facility Pneumatic Controller Compliance Plan and Company-Wide Compressor Station Pneumatic Controller Compliance Plans, (4) For any operator utilizing III.C.4.c.(iv), the records described in Section III.C.4.c.(iv) that demonstrate the owner or operator qualifies under that provision, and (5) For each pneumatic controller required to be tagged pursuant to Sections III.C.4.d.(iv), III.C.4.d.(vi)(B), III.C.4.e.(ii), or III.C.4.e.(iii), a list of each tagged pneumatic controller, equipment location, and its tag identification number.

In accordance with §§ 25-7-105.1 and 25-7-133(3), CRS, the Commission states the rules in Part D, Section II of Regulation Number 7 adopted in this rulemaking are state-only requirements and are not intended as additions or revisions to Colorado's SIP at this time, other than those revising definitions currently in the SIP.

These revisions do not exceed or differ from the federal act due to state flexibility in determining what control strategies to implement to reduce emissions. However, where the proposal may differ from federal rules under the federal act, in accordance with § 25-7- 110.5(5)(b), CRS, the Commission determines:

- (I) The revisions to Regulation Number 7 address equipment and operations in the oil and gas sector including natural gas-driven pneumatic controllers. NSPS OOOO and NSPS OOOOa may also apply to such oil and gas facilities and operations. The revisions to Regulation Number 7 apply on a broader basis to more natural gas-driven pneumatic controllers than the NSPS.
- (II) The Federal rules discussed in (I) are primarily technology-based in that they largely prescribe the use of specific technologies or work practices to comply. EPA has provided some flexibility in NSPS OOOOa by allowing a company to apply to EPA for an alternative means of emission limitations.
- (III) The revisions to Regulation Number 7 strengthen Colorado's state-only provisions. These revisions currently address emissions from the oil and gas sector in a cost-effective manner, allowing for continued growth of Colorado's oil and gas industry.
- (IV) The revisions to Regulation Number 7, Part D establish reasonable equity for oil and gas owners and operators subject to these rules by providing the same standards for similarly situated and sized sources.
- (V) Where necessary, the revisions to Regulation Number 7 include monitoring, recordkeeping, and reporting requirements that correlate, where possible, to similar federal or state requirements.
- (VI) Demonstrated technology is available to comply with the revisions to Regulation Number 7. Some of the revisions expand upon requirements already applicable, such as the requirements for pneumatic controllers.
- (VII) As set forth in the Economic Impact Analysis, the revisions to Regulation Number 7 will reduce emissions in a cost-effective manner.

- (VIII) Alternative rules could also provide reductions in ozone, VOC, methane, and other hydrocarbons to address SB 19-181 and help to attain the NAAQS. SB 19- 181 specifically directs the Commission to “consider” revising its rules to adopt more stringent requirements related to pneumatic devices. The Commission determined that the alternate proposal was reasonable and cost-effective.

As part of adopting the revisions to Regulation Number 7, the Commission has taken into consideration each of the factors set forth in CRS § 25-7-109(1)(b).

To the extent that CRS § 25-7-110.8 requirements apply to this rulemaking, and after considering all the information in the record, the Commission hereby makes the determination that:

- (I) These rules are based upon reasonably available, validated, reviewed, and sound scientific methodologies, and the Commission has considered all information submitted by interested parties.
 - (II) Evidence in the record support the finding that the rules shall result in a demonstrable reduction of methane, VOCs, and other hydrocarbons.
 - (III) Evidence in the record supports the finding that the rules shall bring about reductions in risks to human health and the environment that justify the costs to implement and comply with the rules.
 - (IV) The rules are the most cost-effective to achieve the necessary and desired results, provide the regulated community flexibility, and achieve the necessary reduction in air pollution.
 - (V) The rule will maximize the air quality benefits of the regulation in the most cost-effective manner.
-



Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance

June 1997
Revised November 1998
Revised January 2000
Revised August 2001
Revised July 28, 2004 (specific guidance for Jonah/Pinedale Anticline Area)
Revised August 2007
Revised March 2010
Revised September 2013 (Added specific guidance for UGRB and revisions to JPAD)
Revised May 2016

Under § 35-11-801(e) of the Wyoming Environmental Quality Act, construction or modification of an oil and gas exploration or production well may occur prior to permitting, as long as the facility (1) is not a major source; (2) is permitted within 90 days of the first date of production (FDOP); and (3) applies Best Available Control Technology (BACT). However, any owner or operator may instead apply for a construction or modification permit under Chapter 6, Section 2 of the Wyoming Air Quality Standards and Regulations prior to construction or modification of a facility.

This interpretive guidance discusses the Division's current understanding of BACT for the purpose of assisting owners and operators who choose to construct or modify oil and gas production facilities prior to initiating the permitting process. This interpretive policy is not binding on the agency, the regulated community, or any person; it is for informational purposes and does not create any rights, responsibilities, or liabilities for the Division, members of the regulated community, or any other person.

Owners and operators should be advised that this Guidance represents the agency's current understanding of BACT as of May 12, 2016.

This Guidance applies to surface oil and gas production facilities where hydrocarbon fluids are produced, processed and/or treated prior to custody transfer from the facility.

This Guidance does not apply to sour (H₂S containing) oil production sites. This Guidance also may not be used for sour gas (H₂S) production facilities unless the only emissions of H₂S will be those associated with fugitive losses from valves, fittings, surface piping and pneumatic devices, etc. If there will be H₂S emissions associated with vented gas or tank vapors or if sour gas will be flared the applicant shall contact the Division for permitting guidance prior to construction to determine BACT requirements.

This Guidance does not apply to greenhouse gas emissions (GHGs) or major sources as defined under Wyoming Air Quality Standards and Regulations Chapter 6, Section 3 or Chapter 6, Section 13.

This Guidance does not apply to reciprocating internal combustion engines located at oil and gas production facilities unless the engine is natural gas-fired, used to power a pumping unit, is less than or equal to 50 horsepower, and meets BACT. Reciprocating internal combustion engines larger than 50 horsepower are required to obtain an air quality permit or permit waiver prior to installation.

The Presumptive BACT permitting requirements under this Guidance apply to facilities with associated wells that have a first date of production (FDOP) on/after July 1, 2016 and to facilities with a modification occurring on/after July 1, 2016.

Start up or modification of a facility may occur prior to obtaining an Air Quality Permit or Waiver only when the Presumptive BACT permitting requirements under this Guidance are met. Otherwise, an Air Quality Permit or Waiver shall be obtained prior to start up or modification of a facility.

For the purposes of this Guidance **SWA (STATEWIDE AREA)** refers to all facilities not located in the **UGRB** or **JPAD/NPL**.

UGRB refers to facilities located in the **Upper Green River Basin**.

JPAD/NPL refers to facilities located in the **Jonah and Pinedale Anticline Development Area and Normally Pressured Lance**.

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Acronyms and Abbreviations

AQD	Air Quality Division	NESHAP	National Emission Standards for Hazardous Air Pollutants
API	American Petroleum Institute	NOI	Notice of Installation
BACT	Best Available Control Technology	NOV	Notice of Violation
BBL	barrel	NO _x	Nitrogen Oxides
BPD	barrels per day	NSPS	New Source Performance Standards
BTEX	Benzene/Toluene/ Ethyl-benzene/Xylenes	NSR	New Source Review
Btu	British thermal unit	O&G	Oil and Gas
C6 S2	Chapter 6 Section 2 (of the WAQSR)	P-BACT	Presumptive BACT
CAA	Clean Air Act Amendments of 1990	pph	pounds per hour
CO	Carbon Monoxide	PPMV	parts per million by volume
EPA	Environmental Protection Agency	PSD	Prevention of Significant Deterioration
FEM	Fugitive Emissions Monitoring	psig	pounds per square inch gauge
FWKO	Free water knockout	psia	pounds per square inch absolute
gpm	gallons per minute	SCF	standard cubic foot
H ₂ S	Hydrogen Sulfide	SO ₂	Sulfur Dioxide
HAP	Hazardous Air Pollutants	S/W/B	Standing/Working/Breathing losses
HP	high pressure	TEG	Tri-Ethylene Glycol
Hp	horsepower	TPY	Tons per Year
IMPACT	<u>I</u> nventory, <u>M</u> onitoring, <u>P</u> ermitting, <u>A</u> nd <u>C</u> ompliance <u>T</u> racking online data system	VOC	Volatile Organic Compounds
lb	pound	WAQSR	Wyoming Air Quality Standards and Regulations
LP	low pressure	WDEQ	Wyoming Department of Environmental Quality
MMBtu	one million BTUs		
MMSCF	one million standard cubic feet (SCF × 10 ⁶) (MMSCFD = 1,000,000 SCF per day)		
MSCF	one thousand standard cubic feet (SCF×1000) (MSCFD=1000 SCF per day)		



Introduction

The Oil and Gas Production Facilities Chapter 6 Section 2 Permitting Guidance (C6 S2 Guidance) document is an interpretive policy intended to publicize the Division's current understanding of BACT for certain types of emission sources at certain types of oil and gas production facilities. This interpretive policy is not binding on the agency, the regulated community, or any person; it is for informational purposes and does not create any rights, responsibilities, or liabilities for the Division, members of the regulated community, or any person. Any owners or operators seeking site-specific BACT analyses may choose to follow the standard Chapter 6, Section 2 permitting process prior to the construction or modification of a facility.



Applicability

When is a permit needed?

If **ANY** air pollutant will be released to the atmosphere from a new or modified facility, the facility is subject to the Wyoming Air Quality Standards and Regulations (**WAQSR**) and the Wyoming Environmental Quality Act. This Guidance does not apply to greenhouse gas emissions, sour oil production sites, or reciprocating internal combustion engines greater than 50 horsepower. This Guidance also may not be used for sour gas production facilities unless the only emissions of H₂S will be those associated with fugitive losses from valves, fittings, surface piping and pneumatic devices, etc.

Owners/operators of **ALL** regulated air emission sources constructed or modified after May 29, 1974 shall comply with the WAQSR Chapter 6, Section 2 permitting requirements. To obtain a copy of the WAQSR contact the Wyoming Air Quality Division at (307) 777-7391 or download an electronic version from the Wyoming Secretary of State (<http://soswy.state.wy.us/Rules/default.aspx>). A link to the Secretary of State's website is available on the WDEQ's Air Quality website at <http://deq.wyoming.gov/aqd/>.

Under the Wyoming Environmental Quality Act, certain oil and gas production facilities may be constructed or modified prior to obtaining a permit or waiver, as long as they are minor sources, obtain a permit within 90 days of FDOP, and utilize BACT. Wyo. Stat. Ann. § 35-11-801(e).

Failure to comply with the Wyoming Environmental Quality Act and Wyoming Air Quality Regulations may result in an enforcement action undertaken by the State in the form of a "Notice of Violation", a complaint filed in District Court, or any other enforcement action allowed by law. The Wyoming Environmental Quality Act authorizes the assessment of penalties of up to \$10,000.00 per violation per day and/or injunctive relief.

Which pollutants are associated with oil and gas (O&G) production facilities?

The following air pollutants are commonly associated with O&G production facilities:

Volatile Organic Compounds (VOC): Hydrocarbon compounds excluding methane (C_1) and ethane (C_2). VOCs are also referred to as C_3^+ compounds – propane, butane, pentane, hexane, etc.

Hazardous Air Pollutants (HAP): HAPs commonly associated with O&G production are BTEX and n-hexane (benzene, toluene, ethyl-benzene, xylenes and n- C_6). Section 112(b) of the Clean Air Act identified the regulated HAPs.

Nitrogen Oxides (NO_x): NO_x emissions are the result of natural gas combustion.

Carbon Monoxide (CO): CO emissions are the result of natural gas combustion.

Hydrogen Sulfide (H_2S): Contained within fields that produce sour gas.

Sulfur Dioxide (SO_2): Created when H_2S is combusted.



Production Facility Emission Sources

O&G production facilities emission sources:

Storage Tanks: Vapors containing regulated air pollutants are released from solution as oil, condensate and water are transferred from separation equipment to atmospheric storage tanks. These vapors are called **flashing losses**. Vapors evaporated or displaced from tanks are called **working and breathing (also called standing) losses (S/W/B)**.

Dehydration Units: Glycol, usually tri-ethylene glycol (TEG), is used in dehydration units to absorb water from wet produced gas. “Lean” TEG contacts the wet gas and absorbs water. The TEG, now considered “rich” is routed through a flash separator and/or reboiler for regeneration. Vapors released from the flash separator and reboiler still vent contain regulated air pollutants.

Pressurized Process Vessels: Vapors vented from gun barrels, separators, treaters, water knockouts, gas boots, flash separators, drip pots, etc. contain regulated air pollutants. The discharge lines and vents from all of these vessels shall be considered when determining emission sources.

Natural Gas-Fired Equipment: Some of the byproducts of natural gas combustion in process heaters, boilers, burners, flares, engines, etc. are regulated air pollutants.

Fugitives: All production facilities contain numerous equipment components such as valves, flanges, threaded connections, tubing connections, open-ended lines, pump seals, etc., which are manufactured and installed in ways intended to contain gases or liquids. Over time some of them begin to leak. Emissions associated with leaks are called fugitive emissions. For purposes of this Guidance, emissions from components that are improperly designed (e.g. enardo valves over pressurizing, failure of thief hatches to reseal after over pressurizing) or equipment not maintained properly (e.g., thief hatch left open) are not considered to be fugitive emissions.

Pneumatic Pumps & Controllers: The discharge vapors from natural gas-operated pneumatic equipment contain regulated air pollutants.

Truck Loading: Vapors displaced from truck tanks during the loading of produced liquids that contain regulated air pollutants.

Venting & Blowdown: Natural gas and liquids contain regulated air pollutants.

Well Completions: Activities that occur after a well is drilled that are undertaken to produce hydrocarbon fluids from the well. These include casing, cementing, perforating, gravel packing and installing a production tree.

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BACT and Presumptive BACT

Under WAQSR Chapter 6, Section 2(c), all new or modified sources or facilities, which may generate regulated air emissions shall be permitted prior to construction or modification and **Best Available Control Technology (BACT)** shall be applied to reduce or eliminate emissions, with consideration given for technical feasibility and economical reasonableness. **BACT** is a process, not an emission limit. Regulations do not set a minimum emission threshold below which **BACT** does not need to be considered.

At O&G facilities production rates and associated pollutant emissions are usually unknown prior to start up. The AQD has tailored a permitting program allowing for the start up or modification of O&G facilities prior to permitting provided specific emission control requirements are met.

This is the **Presumptive BACT** permitting process for O&G production facilities.

Presumptive BACT requirements have been established for emissions associated with:

- Flashing & S/W/B losses from atmospheric storage tanks and pressurized vessels
- Dehydration unit process vents
- Natural gas-operated pneumatic equipment
- Natural gas-fired pumping unit engines
- Truck loading
- Produced water tanks
- Well completions
- Well blowdown/venting

If emissions **are known prior to** construction or modification, a permit shall be obtained **PRIOR TO CONSTRUCTION or MODIFICATION** and BACT, including Presumptive BACT requirements, shall be addressed in the application. Examples include:

- Construction of a central tank battery for collecting and processing production from surrounding existing wells with known production rates
- Consolidation of multiple existing facilities for which production rates have been established
- Installation of a dehydration unit for an existing well with an established gas production rate
- Installation of larger capacity equipment to replace undersized equipment
- Replacement of an emission control system or device with a different system or device

Presumptive BACT requirements have been established for three (3) areas:

SWA refers to all facilities not located in the **UGRB** or **JPAD/NPL**.

UGRB refers to facilities located in the **Upper Green River Basin**.

JPAD/NPL refers to facilities located in the **Jonah and Pinedale Anticline Development Area and Normally Pressured Lance**.

The **UGRB** area is defined, in accordance with the public land survey system, as:

Sublette County: (all)

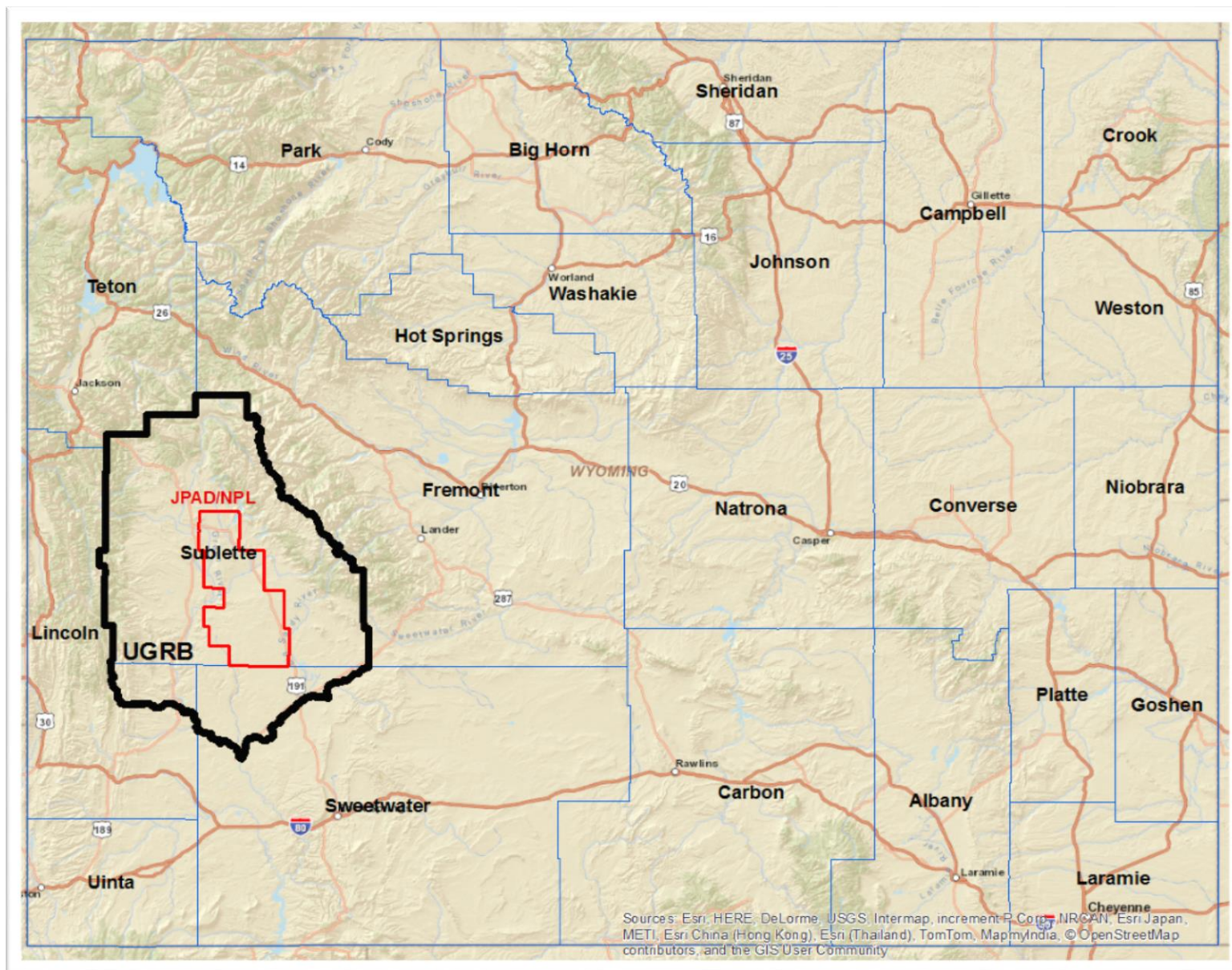
Lincoln County: (part) The area of the county north and east of the boundary defined by a line starting at the point defined by the intersection of the southwest corner Section 30 Range (R) 115 West (R115W) Township (T) 27 North (T27N) and the northwest corner of Section 31 R115W T27N of Sublette County at Sublette County's border with Lincoln County. From this point the boundary moves to the west 500 feet to the Aspen Creek. The boundary follows the centerline of Aspen Creek downstream to the confluence of Aspen Creek and Fontenelle Creek (in R 116 W T26N Section 1). From this point the boundary moves generally to the south along the centerline of Fontenelle Creek to the confluence of Fontenelle Creek and Roney Creek (in R115W T24N Section 6). From the confluence, the boundary moves generally to the east along the centerline of Fontenelle Creek and into the Fontenelle Reservoir (in R112W T24N Section 6). The boundary moves east southeast along the centerline of the Fontenelle Reservoir and then toward the south along the centerline of the Green River to where the Green River in R111W T24N Section 31 crosses into Sweetwater County.

Sweetwater County: (part) The area of the county west and north of the boundary which begins at the midpoint of the Green River, where the Green River enters Sweetwater County from Lincoln County in R111W T24N Section 31. From this point, the boundary follows the center of the channel of the Green River generally to the south and east to the confluence of the Green River and the Big Sandy River (in R109W T22N Section 28). From this point, the boundary moves generally north and east along the centerline of the Big Sandy River to the confluence of the Big Sandy River with Little Sandy Creek (in R106W T25N Section 33). The boundary continues generally toward the northeast long the centerline of Little Sandy Creek to the confluence of Little Sandy Creek and Pacific Creek (in R106W T25N Section 24). From this point, the boundary moves generally to the east and north along the centerline of Pacific Creek to the confluence of Pacific Creek and Whitehorse Creek (in R103W T26N Section 10). From this point the boundary follows the centerline of Whitehorse Creek generally to the northeast until it reaches the eastern boundary of Section 1 R103W T26N. From the point where Whitehorse Creek crosses the eastern section line of Section 1 R103W T26N, the boundary moves straight north along the section line to the southeast corner of Section 36 R103W T27N in Sublette County where the boundary ends.

The **JPAD/NPL** area is defined as:

Sublette County: R109W & R110W in T34N,
R109W & R110W in T33N,
R108W, R109W & R110W in T32N,
R108W, R109W & R110W in T31N,
R107W, R108W & R109W in T30N,
R107W, R108W, R109W, & R110W in T29N,
R107W, R108W, R109W, & R110W in T28N,
and R107W, R108W & R109W in T27N

The **SWA** refers to all other areas in the State excluding the **UGRB** or **JPAD/NPL**.





Presumptive BACT Requirements for SWA Facilities

Flashing

For the purpose of determining flashing emissions all vapor streams containing VOC and/or HAP components from all storage tanks (e.g., oil, condensate, produced water with oil or condensate carryover) and all separation vessels (e.g., gun barrels, production and test separators, production and test treaters, water knockouts, gas boots, flash separators, drip pots, etc.) at a facility, which are or may be vented to the atmosphere shall be considered.

New Facilities

PAD Facilities

Upon First Date of Production (FDOP), VOC and HAP flashing emissions shall be controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of FDOP, flashing emissions containing greater than or equal to 6 Tons per Year (TPY) VOC and HAPs shall be controlled by at least 98%.

Modified Facilities

PAD Facilities

Upon modification, all new and existing VOC and HAP flash emissions shall be controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of modification, all new and existing flashing emissions containing greater than or equal to 6 TPY VOC and HAPs shall be controlled by at least 98%.

New and Modified Facilities

Condensate and oil tanks that are on site solely for use during emergency or upset conditions, such as spare tanks at facilities connected to liquids gathering systems, are not subject to the 98% control requirements.

The removal of a flashing emissions control device(s) may be allowed upon approval if, after at least one year from the date of installation, VOC and HAP flashing emissions have declined to less than, and are reasonably expected to remain below 4 TPY of VOC and HAPs.



Presumptive BACT Requirements for SWA Facilities (cont.)

Dehydration Units

For the purpose of determining emissions from dehydration units, vapor streams containing VOC or HAP components released from the process vents (reboiler still vents & glycol flash separator vents) of all dehydration units at a facility, which are or may be vented to the atmosphere shall be considered. See page 9 for the definitions of **potential uncontrolled** VOC and HAP emissions and **potential** VOC and HAP emissions.

New Facilities

Upon FDOP, all dehydration units shall be equipped with reboiler still vent condensers. Removal of the condensers will not be allowed.

PAD Facilities

Upon FDOP, all dehydration unit VOC and HAP emissions shall be controlled by at least 98%. After one year, combustion units used to achieve the 98% control may be removed upon approval if

- Total **potential** VOC and HAP emissions from all units are less than 4 TPY and
- All units are equipped with still vent condensers.

Single Well Facilities

Within 60 days of FDOP, if total **potential uncontrolled** VOC and HAP emissions from all units are greater than or equal to 6 TPY, emissions from all units shall be controlled by at least 98%.

After one year, combustion units used to achieve the 98% control may be removed upon approval if

- Total **potential** VOC and HAP emissions from all units are less than 4 TPY and
- All units are equipped with still vent condensers.

Modified Facilities

Requirements are the same as those for PADs and single well facilities except use the date of modification in place of FDOP. Control requirements apply to all existing and new dehydration units.

All Facilities

When a combustion unit is required at a facility for control of dehydration unit emissions, all non-condensable still vent vapors shall be collected and routed to a combustion unit for at least 98% control of VOC and HAP emissions. All glycol flash separator vapors shall be collected and routed to the combustion unit for at least 98% control of VOC and HAP emissions and/or used as fuel for process equipment burners.



Presumptive BACT Requirements for SWA Facilities (cont.)

All Facilities (cont.)

At facilities where a combustion unit is not required for control of flash or dehydration unit emissions, all glycol flash separator vapors shall be collected for use as fuel in process equipment burners. Excess flash vapors that are not used as fuel may be vented to the atmosphere.

Potential Uncontrolled VOC and HAPs emissions shall be determined using GRI-GLYCalc version 4.0 (V4.0) or higher or other method accepted by the Division and shall be based on the projected, year one, average daily dry gas throughput rate, maximum circulation rate for the glycol circulation pump(s) installed, average expected operating parameters for wet gas temperature and pressure, maximum dry gas water content or number of absorber stages and extended hydrocarbon content of the wet gas from a sample of the wet gas taken upstream of the dehydration unit contact tower. Flash separators, still vent condensers, limited operating hours, and limited glycol circulation rates shall not be considered when determining potential uncontrolled emissions.

Still vent condensers shall consist of equipment engineered and designed to achieve maximum condensation of the condensable components in the still vent vapors by providing adequate temperature differentials between the condenser outlet and still vent stream. Still vent pipes shall not be considered condensers.

Potential emissions for determining combustion device removal after one year shall be calculated using GRI-GLYCalc V4.0 or higher or other method accepted by the Division based on the past twelve calendar months of normal gas production rates, actual average wet gas temperature and pressure, actual water content of the dried gas or number of absorber stages.

Actual operating parameters for glycol flash separators may be used upon approval. Limited operating hours and limited glycol circulation rates shall not be considered for control removal.



Presumptive BACT Requirements for SWA Facilities (cont.)

Pneumatic Pumps

New Facilities

PAD Facilities

Upon FDOP, VOC and HAP emissions associated with the discharge streams of all natural gas-operated pneumatic pumps shall be controlled by at least 98% or the pump discharge streams shall be routed into a closed loop system (e.g., sales line, collection line, fuel supply line).

Single Well Facilities and Tank Batteries

Within 60 days of FDOP,

At sites with controls installed for flashing or dehydration unit emissions:

VOC and HAP emissions associated with the discharge streams from natural gas-operated pneumatic pumps shall be controlled by at least 98% or the discharge streams shall be routed into a closed loop system.

At sites without controls installed for flashing or dehydration unit emissions:

Pneumatic pumps (other than heat trace/heat medium/hot glycol circulation) shall be solar, electric or air-driven pumps in lieu of natural gas-operated pneumatic pumps or the discharge streams shall be routed into a closed loop system. Wherever possible, heat trace/heat medium/hot glycol circulation pumps shall be solar-operated, electric or air-driven.

Modified Facilities

Requirements are the same as above except include all new and existing pneumatic pumps and use the date of modification in place of FDOP.

New and Modified Facilities

At sites where pneumatic pump emissions are controlled by a combustion unit used for the control of flashing or dehydration unit emissions, control of the pneumatic pump emissions will be evaluated upon request for removal of the combustion unit. (See Flashing, Page 7)



Presumptive BACT Requirements for SWA Facilities (cont.)

Pneumatic Controllers

New Facilities

Upon FDOP, natural gas-operated pneumatic controllers shall be low bleed or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Modified Facilities

Upon modification, new natural gas-operated pneumatic controllers shall be low or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Within 60 days of modification, existing natural gas-operated pneumatic controllers shall be replaced by or converted to low or zero bleed controllers or the discharge streams of existing natural gas-operated pneumatic controllers shall be routed into a closed loop system.

Truck Loading

New Facilities

Within 60 days of FDOP, loading emissions containing greater than or equal to 6 TPY VOC and HAP emissions shall be controlled. Operators are expected to utilize a vapor collection system or equivalent device for the truck loading operation that is assumed, based on AP-42 Section 5.2, to capture a minimum of 70% of the truck loading vapors. The captured vapors are to be routed to a smokeless combustion device with a reported destruction efficiency of 98%, or routed to an equivalent control.

Modified Facilities

Upon modification, all new and existing VOC and HAP loading emissions containing greater than or equal to 6 TPY VOC and HAP emissions shall be controlled. Operators are expected to utilize a vapor collection system or equivalent device for the truck loading operation that is assumed, based on AP-42 Section 5.2, to capture a minimum of 70% of the truck loading vapors. The captured vapors are to be routed to a smokeless combustion device with a reported destruction efficiency of 98%, or routed to an equivalent control.

New and Modified Facilities

The removal of a control device(s) may be allowed upon approval if after at least one year from the date of installation VOC and HAP loading emissions have declined to less than, and are expected to remain below 4 TPY of VOC and HAPs.

Note: Safety issues associated with the control of truck loading emissions will be taken into consideration by the Division. Applicants will be required to demonstrate that safety issues would preclude the application of controls, and the demonstration will have to be approved by the Division prior to the date that controls would be required under the Guidance.



Presumptive BACT Requirements for SWA Facilities (cont.)

Well Completions

Operators shall submit applications to perform well completions using Best Management Practices. One permit will be issued to each company that drills and completes wells within the State. An example of a well completions or “Green Completions” permit is available on the AQD website, <http://deq.wyoming.gov/aqd/new-source-review> or a copy may be obtained by contacting the Wyoming Air Quality Division at (307) 777-7391.

For existing operators, Green Completion permit applications shall be filed with the Division by January 1, 2017. For new operators, a Green Completion permit application shall be filed with the first application for a production site.

Produced Water Tanks

New Facilities

PAD Facilities

Upon FDOP, VOC and HAP emissions from all active produced water tanks shall be controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of FDOP, at sites where flashing emissions must be controlled by at least 98%, VOC and HAP emissions from all active produced water tanks shall be controlled by at least 98%.

Modified Facilities

PAD Facilities

Upon modification, VOC and HAP emissions from all new active produced water tanks shall be controlled by at least 98%.

Within 60 days of modification, existing open-top, active, produced water tanks shall be taken out of service for use as active produced water tanks. All active produced water tanks shall be closed top and shall have VOC and HAP emissions controlled by at least 98%.

New and Modified Facilities

Produced water tanks that are on site solely for use during emergency or upset conditions, such as spare tanks at facilities connected to liquids gathering systems, are not subject to the 98% control requirements.

The removal of a emissions control device(s) may be allowed upon approval if, after at least one year from the date of installation, VOC and HAP flashing emissions have declined to less than, and are reasonably expected to remain below 4 TPY of VOC and HAPs.



Presumptive BACT Requirements for SWA Facilities (cont.)

Blowdown/Venting

Best Management Practices (BMP) and information gathering requirements for new and modified facilities.

BMP: During manual and automated blowdown/venting episodes associated with liquids unloading, wellbore depressurization in preparation for maintenance or repair, hydrate clearing, emergency operations, equipment depressurization, etc., associated VOC and HAP emissions shall be minimized to the extent practicable. During manual blowdown or venting, personnel shall remain on site to ensure minimal gas venting occurs.

Information Gathering: Specific recordkeeping and reporting requirements will be established during the permitting process and will include estimates of associated regulated air pollutants, reasons for episodes, durations of episodes, steps taken to minimize emissions and descriptions of emission estimation methods.

For existing operators, well blowdown and venting permit applications shall be filed with the Division by January 1, 2017. For new operators, a well blowdown and venting permit application shall be filed with the first application for a production site.

Emission Sources without Presumptive BACT requirements

For uncontrolled sources emitting greater than or equal to 6 TPY VOC and HAP emissions, that do not have P-BACT requirements, a BACT analysis shall be filed with the permit application for the associated facility.

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Presumptive BACT Requirements for UGRB Facilities

Flashing

For the purpose of determining flashing emissions all vapor streams containing VOC or HAP components from all storage tanks (e.g., oil, condensate, produced water with oil or condensate carryover) and all separation vessels (e.g., gun barrels, production and test separators, production and test treaters, water knockouts, gas boots, flash separators, drip pots, etc.) at a facility, which are or may be vented to the atmosphere shall be considered.

New Facilities

PAD Facilities

Upon FDOP, VOC and HAP flashing emissions shall be controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of FDOP, flashing emissions containing greater than or equal to 4 TPY VOC and HAPs shall be controlled by at least 98%.

Modified Facilities

PAD Facilities

Upon modification, all new and existing VOC and HAP flash emissions shall be controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of modification, all new and existing flashing emissions containing greater than or equal to 4 TPY VOC and HAPs shall be controlled by at least 98%.

New and Modified Facilities

Condensate and oil tanks that are on site for use during emergency or upset conditions, such as spare tanks at facilities connected to liquids gathering systems, are not subject to the 98% control requirements.

The removal of flashing emissions control devices may be allowed upon approval after one year if VOC flashing emissions have declined to less than, and are reasonably expected to remain below 4 TPY.



Presumptive BACT Requirements for UGRB Facilities (cont.)

Dehydration Units

For the purpose of determining emissions from dehydration units, vapor streams containing VOC or HAP components released from the process vents (reboiler still vents & glycol flash separator vents) of all dehydration units at a facility, which are or may be vented to the atmosphere shall be considered. See page 9 for the definitions of **potential uncontrolled** VOC and HAP emissions and **potential** VOC and HAP emissions.

New Facilities

Upon FDOP, all dehydration units shall be equipped with reboiler still vent condensers. Removal of the condensers will not be allowed.

PAD Facilities

Upon FDOP, all dehydration unit VOC and HAP emissions shall be controlled by at least 98%. After one year, combustion units used to achieve the 98% control may be removed upon approval if

- Total **potential** VOC and HAP emissions from all units are less than 4 TPY and
- All units are equipped with still vent condensers.

Single Well Facilities

Within 60 days of FDOP, if total **potential uncontrolled** VOC and HAP emissions from all units are greater than or equal to 4 TPY, emissions from all units shall be controlled by at least 98%.

After one year, combustion units used to achieve the 98% control may be removed upon approval if

- Total **potential** VOC and HAP emissions from all units are less than 4 TPY and
- All units are equipped with still vent condensers.

Modified Facilities

Requirements are the same as those for PADs and single well facilities except use the date of modification in place of FDOP. Control requirements apply to existing and new dehydration units.

All Facilities

When a combustion unit is required at a facility for control of flash or dehydration unit emissions, all non-condensable still vent vapors shall be collected and routed to the combustion unit for at least 98% control of VOC and HAP emissions and all glycol flash separator vapors shall be collected and routed to the combustion unit for at least 98% control of VOC and HAP emissions and/or used as fuel for process equipment burners.

At facilities where a combustion unit is not required for control of flash or dehydration unit emissions, all glycol flash separator vapors shall be collected for use as fuel in process equipment burners. Excess flash vapors that are not used as fuel may be vented to the atmosphere.



Presumptive BACT Requirements for UGRB Facilities (cont.)

Pneumatic Pumps

New Facilities

Upon FDOP, VOC and HAP emissions associated with the discharge streams of all natural gas-operated pneumatic pumps shall be controlled by at least 98% or the pump discharge streams shall be routed into a closed loop system (e.g., sales line, collection line, fuel supply line).

Modified Facilities

Upon modification, VOC and HAP emissions associated with the discharge streams of all new and existing natural gas-operated pneumatic pumps shall be controlled by at least 98% or the pump discharge streams shall be routed into a closed loop system.

New and Modified Facilities

At sites where pneumatic pump emissions are controlled by a combustion unit used for the control of flash or dehydration unit emissions, control of the pneumatic pump emissions will be evaluated upon request for removal of the combustion unit. (See Flashing, Page 14)

Pneumatic Controllers

New Facilities

Upon FDOP, natural gas-operated pneumatic controllers shall be low or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Modified Facilities

Upon modification, new natural gas-operated pneumatic controllers shall be low or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Within 60 days of modification, existing natural gas-operated pneumatic controllers shall be replaced by or converted to low or zero bleed controllers or the discharge streams of existing natural gas-operated pneumatic controllers shall be routed into a closed loop system.



Presumptive BACT Requirements for UGRB Facilities (cont.)

Fugitives

For new and modified facilities where fugitive emissions are greater than or equal to 4 TPY of VOCs, operators shall submit a Fugitive Emissions Monitoring (FEM) Protocol. The fugitive emission monitoring in the FEM Protocol shall be no less frequent than quarterly, and may consist of Method 21, infrared camera, audio-visual-olfactory (AVO) inspections, or some combination thereof and must be approved by the Division. A proposed FEM Protocol consisting of only AVO inspections will not be accepted by the Division.

Truck Loading

New Facilities

Within 60 days of FDOP, loading emissions containing greater than or equal to 6 TPY VOC and HAP emissions shall be controlled. Operators are expected to utilize a vapor collection system or equivalent device for the truck loading operation that is assumed, based on AP-42 Section 5.2, to capture a minimum of 70% of the truck loading vapors. The captured vapors are to be routed to a smokeless combustion device with a reported destruction efficiency of 98%, or routed to an equivalent control.

Modified Facilities

Upon modification, all new and existing VOC and HAP loading emissions containing greater than or equal to 6 TPY VOC and HAP emissions shall be controlled. Operators are expected to utilize a vapor collection system or equivalent device for the truck loading operation that is assumed, based on AP-42 Section 5.2, to capture a minimum of 70% of the truck loading vapors. The captured vapors are to be routed to a smokeless combustion device with a reported destruction efficiency of 98%, or routed to an equivalent control.

New and Modified Facilities

The removal of a control device(s) may be allowed upon approval if after at least one year from the date of installation VOC and HAP loading emissions have declined to less than, and are expected to remain below 4 TPY of VOC and HAPs.

Note: Safety issues associated with the control of truck loading emissions will be taken into consideration by the Division. Applicants will be required to demonstrate that safety issues would preclude the application of controls, and the demonstration will have to be approved by the Division prior to the date that controls would be required under the Guidance.



Presumptive BACT Requirements for UGRB Facilities (cont.)

Well Completions

Operators shall submit applications to perform well completions using Best Management Practices. One permit will be issued to each company that drills and completes wells within the **UGRB**. The permits will be modeled after those issued to operators completing wells in the Jonah and Pinedale Anticline Development Area. An example of a well completions or “Green Completions” permit is available on the AQD website, <http://deq.wyoming.gov/aqd/new-source-review> or a copy may be obtained by contacting the Wyoming Air Quality Division at (307) 777-7391.

Produced Water Tanks

New Facilities

PAD Facilities

Upon FDOP, VOC and HAP emissions from all active produced water tanks shall be controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of FDOP, at sites where flashing emissions must be controlled by at least 98%, VOC and HAP emissions from all active produced water tanks shall be controlled by at least 98%.

Modified Facilities

PAD Facilities

Upon modification, VOC and HAP emissions from all new active produced water tanks shall be controlled by at least 98%.

Within 60 days of modification, existing open-top, active, produced water tanks shall be taken out of service for use as active produced water tanks. All active produced water tanks shall be closed top and shall have VOC and HAP emissions controlled by at least 98%.

Single Well Facilities and Tank Batteries

Within 60 days of modification, at sites where flashing emissions must be controlled by at least 98%, VOC and HAP emissions from all active produced water tanks shall be controlled by at least 98%.

New and Modified Facilities

Open-top or blow down tanks shall not be used as active produced water tanks but may be used for blow down or for temporary storage during emergency or upset conditions, such as spare tanks at facilities connected to liquids gathering systems, and do not have to be tied into 98% control systems.

Removal of produced water tank emissions control may be allowed upon approval. (See Flashing, Page 14)



Presumptive BACT Requirements for UGRB Facilities (cont.)

Blowdown/Venting

Best Management Practices (BMP) and information gathering requirements will be incorporated into permits for new and modified facilities.

BMP: During manual and automated blowdown/venting episodes associated with liquids unloading, wellbore depressurization in preparation for maintenance or repair, hydrate clearing, emergency operations, equipment depressurization, etc., associated VOC and HAP emissions shall be minimized to the extent practicable. During manual blowdown or venting, personnel shall remain on site to ensure minimal gas venting occurs.

Information Gathering: Specific recordkeeping and reporting requirements will be established during the permitting process and will include estimates of associated regulated air pollutants, reasons for episodes, durations of episodes, steps taken to minimize emissions and descriptions of emission estimation methods.

Emission Sources without Presumptive BACT requirements

For uncontrolled sources emitting greater than or equal to 4 TPY VOC that do not have P-BACT requirements, a BACT analysis shall be filed with the permit application for the associated facility.

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Presumptive BACT Requirements for [JPAD/NPL](#) Facilities

Flashing

For the purpose of determining flashing emissions all vapor streams containing VOC or HAP components from all storage tanks (e.g., oil, condensate, produced water with oil or condensate carryover) and all separation vessels (e.g., gun barrels, production and test separators, production and test treaters, water knockouts, gas boots, flash separators, drip pots, etc.) at a facility, which are or may be vented to the atmosphere shall be considered.

New Facilities

Upon FDOP, VOC and HAP flashing emissions shall be controlled by at least 98%.

Modified Facilities

Upon modification, all new and existing VOC and HAP flashing emissions shall be controlled by at least 98%.

New and Modified Facilities

Condensate and oil tanks that are on site for use during emergency or upset conditions, such as spare tanks at facilities connected to liquids gathering systems, are not subject to the 98% control requirements.

The removal of flashing emissions control devices may be allowed upon approval after one year if VOC and HAP flashing emissions have declined to less than, and are reasonably expected to remain below 4 TPY.

Dehydration Units

New Facilities

Upon FDOP, all VOC and HAP emissions from dehydration unit process vents shall be controlled by at least 98%. No control removal will be allowed.

Modified Facilities

Upon modification, all VOC and HAP emissions from new and existing dehydration unit process vents shall be controlled by at least 98%. No control removal will be allowed.



Presumptive BACT Requirements for [JPAD/NPL](#) Facilities (cont.)

Pneumatic Pumps

New Facilities

Upon FDOP, VOC and HAP emissions associated with the discharge streams of all natural gas-operated pneumatic pumps shall be controlled by at least 98% or the pump discharge streams shall be routed into a closed loop system (e.g., sales line, collection line, fuel supply line).

Modified Facilities

Upon modification, VOC and HAP emissions associated with the discharge streams of all new and existing natural gas-operated pneumatic pumps shall be controlled by at least 98% or the pump discharge streams shall be routed into a closed loop system.

New and Modified Facilities

For pneumatic pump emissions controlled by a combustion unit used to control flash emissions which may be removed, the control method for pump emissions will be evaluated upon request for approval to remove the combustion unit. (See Flashing, Page 20)

Pneumatic Controllers

New Facilities

Upon FDOP, natural gas-operated pneumatic controllers shall be low or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Modified Facilities

Upon modification, new natural gas-operated pneumatic controllers shall be low or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.

Within 60 days of modification, existing natural gas-operated pneumatic controllers shall be replaced by or converted to low or zero bleed controllers or the controller discharge streams shall be routed into a closed loop system.



Presumptive BACT Requirements for [JPAD/NPL](#) Facilities (cont.)

Produced Water Tanks

New Facilities

Upon FDOP, VOC and HAP emissions from all active produced water tanks shall be controlled by at least 98%.

Modified Facilities

Upon modification, VOC and HAP emissions from all new active produced water tanks shall be controlled by at least 98%.

Within 60 days of modification, existing open-top, active, produced water tanks shall be taken out of service for use as active produced water tanks. All active produced water tanks shall be closed top and shall have VOC and HAP emissions controlled by at least 98%.

New and Modified Facilities

Open-top or blow down tanks shall not be used as active produced water tanks but may be used for blow down or for temporary storage during emergency or upset conditions, such as spare tanks at facilities connected to liquids gathering systems, and do not have to be tied into 98% control systems.

Removal of water tank emissions control may be allowed upon approval. (See Flashing, Page 20)

Fugitives

For new and modified facilities where fugitive emissions are greater than or equal to 4 TPY of VOCs, operators shall submit a FEM Protocol. The fugitive emission monitoring in the FEM Protocol shall be no less frequent than quarterly, and may consist of Method 21, infrared camera, AVO inspections, or some combination thereof and must be approved by the Division. A proposed FEM Protocol consisting of only AVO inspections will not be accepted by the Division.



Presumptive BACT Requirements for [JPAD/NPL](#) Facilities (cont.)

Truck Loading

New Facilities

Within 60 days of FDOP, loading emissions containing greater than or equal to 6 TPY VOC and HAP emissions shall be controlled. Operators are expected to utilize a vapor collection system or equivalent device for the truck loading operation that is assumed, based on AP-42 Section 5.2, to capture a minimum of 70% of the truck loading vapors. The captured vapors are to be routed to a smokeless combustion device with a reported destruction efficiency of 98%, or routed to an equivalent control.

Modified Facilities

Upon modification, all new and existing VOC and HAP loading emissions containing greater than or equal to 6 TPY VOC and HAP emissions shall be controlled. Operators are expected to utilize a vapor collection system or equivalent device for the truck loading operation that is assumed, based on AP-42 Section 5.2, to capture a minimum of 70% of the truck loading vapors. The captured vapors are to be routed to a smokeless combustion device with a reported destruction efficiency of 98%, or routed to an equivalent control.

New and Modified Facilities

The removal of a control device(s) may be allowed upon approval if after at least one year from the date of installation VOC and HAP loading emissions have declined to less than, and are expected to remain below 4 TPY of VOC and HAPs.

Note: Safety issues associated with the control of truck loading emissions will be taken into consideration by the Division. Applicants will be required to demonstrate that safety issues would preclude the application of controls, and the demonstration will have to be approved by the Division prior to the date that controls would be required under the Guidance.

Well Completions

Operators shall submit applications to perform well completions using Best Management Practices. One permit will be issued to each company that drills and completes wells within the [JPAD/NPL](#). The permits will be modeled after those issued to operators completing wells in the Jonah and Pinedale Anticline Development Area. An example of a well completions or “Green Completions” permit is available on the AQD website, <http://deq.wyoming.gov/aqd/new-source-review> or a copy may be obtained by contacting the Wyoming Air Quality Division at (307) 777-7391.



Presumptive BACT Requirements for [JPAD/NPL](#) Facilities (cont.)

Blowdown/Venting

Best Management Practices (BMP) and information gathering requirements will be incorporated into permits for new and modified facilities.

BMP: During manual and automated blow down/venting episodes associated with liquids unloading, wellbore depressurization in preparation for maintenance or repair, hydrate clearing, emergency operations, equipment depressurization, etc., associated VOC and HAP emissions shall be minimized to the extent practicable. During manual blow down or venting, personnel shall remain on site to ensure minimal gas venting occurs.

Information Gathering: Specific recordkeeping and reporting requirements will be established during the permitting process and will include estimates of associated regulated air pollutants, reasons for episodes, durations of episodes, steps taken to minimize emissions and descriptions of emission estimation methods.

Emission Sources without Presumptive BACT requirements

For uncontrolled sources emitting greater than or equal to 4 TPY VOC and HAPs that do not have P-BACT requirements, a BACT analysis shall be filed with the permit application for the associated facility.

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Determining P-BACT Flashing Emissions

Flashing losses occur when produced liquids (crude oil or condensate) are exposed to temperature increases or pressure drops as they are transferred from production vessels to other vessels or to atmospheric storage tanks. For purposes of this guidance, the term “**flash emissions**” refers to VOC and HAP pollutants associated with entrained natural gas vapors released to the atmosphere from hydrocarbon liquids in surface production equipment. This production equipment may include gun barrels, separators, treaters, produced water tanks, gas drips, freewater knockouts, etc. In addition to flash emissions, vessels containing hydrocarbon liquids also have emissions associated with **working** and **breathing** (also called standing) losses. These are vapors displaced from oil or condensate due to evaporation and agitating.

Use the following steps to determine projected potential flashing and working/breathing losses:

STEP 1: 30 days after the First Date of Production calculate the **average daily condensate or oil production**.

Example: Well produced 600 BBL during the first 30 days after the First Date of Production.
average daily condensate/oil production = $600 \text{ BBL} \div 30 \text{ days} = 20 \text{ BPD}$

STEP 2: Calculate the **projected first year annualized average daily condensate/oil production** rate by multiplying the average 30-day rate times 0.6. This effectively results in a first year, annualized daily production rate, which is 20% of the initial production rate. Additionally, this effectively accounts for an 80% decline in daily production by the end of the first year. (described in more detail on page 36)

Example:

projected first year, annualized average daily oil/condensate production = $20 \times 0.6 = 12 \text{ BPD}$

If the expected decline rate is less than 80%, then the expected decline rate should be used. Using an expected decline rate > 80% requires pre-approval from the Division.

STEP 3: Use an approved flash emissions model or direct measurement of tank emissions to determine **projected first year VOC and HAP emissions associated with the projected first year average daily production rate**.

Actual flash emissions are determined the same as projected potential emissions except that the actual average daily condensate or oil production rate is used rather than a projected production rate.



Determining P-BACT Flashing Emissions (cont.)

Several methods are available to calculate or measure flash emissions with some being more accurate than others. Even though working/breathing/flashing losses are almost always mixed together and exit from a common vent at the same time, some methods only calculate working and breathing losses and some only calculate flashing losses. Some methods will calculate all three types of emissions simultaneously. Each method has specific constraints. For whichever method used, all supporting data used to calculate the emissions, including identification of the calculation method, description of sampling methods and copies of lab sampling analyses shall be provided with the emissions estimate.

	Method	Emissions Calculated	Comments
1	Direct measurement	working, breathing, flash	Sampling and lab analysis required. Results are relatively accurate.
2	Process Simulator	flash, working, breathing	i.e. PROMAX, HYSIM, HYSIS Software is expensive but results are accurate when based on site-specific sampling and lab analysis.
3	API E&P TANKS Software V 2.0 and higher	working, breathing, flash	Requires site specific sampling. Not as accurate as more expensive process simulators and no longer supported by the software producer (American Petroleum Institute).
4	Laboratory measurement of the Gas-Oil-Ratio (GOR) from a pressurized liquid sample	flash only	This is a direct laboratory analysis of the flash vapors emitted from a pressurized oil/condensate sample.
5	EPA TANKS 4.0.9d	working, breathing only	Program distributed by the EPA through their website at https://www3.epa.gov/ttn/chief/software/tanks/index.html

Extended hydrocarbon liquids analyses used for model input shall be no older than **three** years. Composite analyses may be used as input. These are averaged extended hydrocarbon compositions based on samples from at least five wells located in the same geographical area, producing from the same formation and under similar conditions ($\pm 25^\circ$ psig) as the well being permitted. Analyses used as the basis for the average shall be no older than **three** years.



Determining P-BACT Dehydration Unit Emissions

Dehydration units use glycol (TEG, DEG or EG) to absorb water from produced gas before it is introduced into gas sales or collection lines. Upon contact with wet gas, “lean” glycol absorbs water and other liquids. It is then considered “rich”. To remove impurities, or regenerate, the rich glycol is routed through a glycol flash separator and/or a reboiler. During flash separation and reboiling, water and hydrocarbon vapors containing VOC and HAP pollutants are released from the rich glycol. These are then discharged to the atmosphere from the dehydration unit process vents.

Use the following steps to determine projected potential dehydration unit emissions:

STEP 1: Once a new well has produced for 30 days after the First Date of Production, determine the average daily gas production rate.

Example:

*Well produced 100 MMCF during the first 30 days after the First Date of Production
average daily gas production = $100 \text{ MMCF} \div 30 \text{ days} = 3.3 \text{ MMCFD}$*

STEP 2: Calculate the **projected first year, annualized average daily gas production** rate by multiplying the initial average 30-day rate times 0.6. This effectively results in a first year, annualized daily production rate, which is 20% of the initial production rate. Additionally, this effectively calculates an 80% decline in daily production by the end of the first year. (described in more detail on page 36.)

Example:

projected first year, annualized average daily gas production = $3.3 \times 0.6 = 2.0 \text{ MMCFD}$

STEP 3: Use GRI-GLYCalc V4.0 or higher or other method approved by the Division with the projected first year, annualized average daily production rate to determine **potential, annualized uncontrolled VOC and HAP emissions** from the dehydration unit **process vents**. **Process vents** include reboiler still vents, glycol flash separators and still vent condensers.

Model input:

- 1) An extended hydrocarbon analysis of wet gas sampled upstream of the reboiler contact tower. Or, a composite extended hydrocarbon analysis may be used. A composite analysis is the average composition from at least five nearby wells producing from the same formation as the new well and under the same or very similar separator pressure and temperature conditions. Samples shall be no older than three years.
- 2) The projected first year average daily gas production rate (MMCFD).
- 3) Average, actual equipment operational parameters, including wet gas temperature and pressure, dry gas water content, glycol flash separator temperature and pressure, stripping gas source and rate and average operating parameters of emission control equipment.
- 4) The **maximum lean glycol circulation rate** (gpm) for the glycol circulation pump in use. Maximum circulation rates for the most commonly used Kimray Model pumps are listed in **TABLE 1**.



Determining P-BACT Dehydration Unit Emissions (cont.)

TABLE 1

KIMRAY GLYCOL PUMP RATES				
Model #	Capacity (gpm)		Working Pressure (psi)	
	min	max	min	max
3154 PV	0.05	0.22	100	1500
1715 PV	0.13	0.67	300	1500
4015 PV	0.2	0.67	300	1500
9015 PV	0.45	1.5	300	1500
21015 PV	1.1	3.5	400	1500
45015 PV	2.77	7.5	400	1500
4015 LP	0.13	0.33	100	500
2015 SC	0.13	0.33	100	500
5015 SC	0.2	0.83	100	500
10015 SC	0.37	1.67	100	500
20015 SC	1	3.33	100	500

Data from Kimray O&G Equipment and Controls Catalog

Actual dehydration unit emissions are determined the same as projected potential emissions except that the actual average daily gas production rate is used in the GLYCalc model rather than a projected production rate.



BACT for Flashing Emissions

The following control systems or devices are accepted by the Division as meeting BACT for flash emissions:

- 1) A vapor recovery device that is designed and operated and may be demonstrated to reduce the mass content of VOC and total HAP emissions in the vapors vented to the device by at least 98%.
- 2) An enclosed, smokeless combustion device or flare that is designed and operated and may be demonstrated to reduce the mass content of VOC and total HAP emissions in the vapors vented to the device by at least 98%.
- 3) Any other control device or configuration that can be demonstrated to reduce the mass content of total HAP and VOC in the process gases vented to the device or configuration by at least 98%.
- 4) Monitoring and recordkeeping, which will demonstrate continuous and effective emission control are required upon start up of the control system. For a combustion device this may be a thermocouple and continuous recording device or any other equivalent device to detect and record the presence of the pilot flame, or a combustion chamber temperature recorder/monitor. The monitoring/recording requirements become enforceable permit conditions.
- 5) Emissions control equipment, systems or devices, all vent lines, connections, fitting, valves, relief valves, thief hatches or any other appurtenance employed to contain and collect vapors and transport them to the emission control system or device, shall be maintained and operated during any time a well is producing such that the emissions are controlled at all times.

CAUTION: Total emissions from any facility or source shall not exceed major source levels prior to emission control installation. Major source levels are 10 TPY of any single HAP, 25 TPY of any combination of HAP or 100 TPY of any regulated pollutant. Flash emissions prior to control installation will be determined using approved emission models or methods based on actual reported production and operating conditions. Reported production includes that sold during well completion activities, which are reported to the WOGCC. Flash emissions are directly proportional to production rates, provided operational parameters remain consistent, so it is acceptable to prorate emissions based on production.



BACT for Dehydration Unit Emissions

Other emission control systems or devices than those previously discussed may be used upon approval by the Division to meet BACT requirements for emissions from dehydration unit process vents (reboiler still vents and vents from glycol flash separators or glycol flash tanks). In order to be approved, the operator must provide a demonstration certifying the system or device will reduce the mass content of total HAP and VOC in the process gases vented to the device or configuration by at least 98%.

Emissions control equipment, systems or devices, all vent lines, connections, fitting, valves, relief valves, hatches or any other appurtenance employed to contain and collect vapors and transport them to the emission control system or device, shall be maintained and operated during any time a well is producing such that the emissions are controlled at all times.

Monitoring and recordkeeping, which will demonstrate continuous and effective emission control are required upon start up of the control system. For combustion devices this may be a thermocouple and continuous recording device for the pilot flame or any other equivalent device to detect and record the presence of the pilot flame. A temperature recorder/monitor might be used to demonstrate sufficient heat of combustion or a continuous, wind-up chart recorder might be used to demonstrate continual operation by measuring and recording temperature or pressure parameters.

REMINDER: Dehydration units at oil and gas production facilities may be subject to additional NESHAP requirements under 40 CFR part 63, subpart HH. It is the operator's responsibility to comply with all applicable requirements of the NESHAP regulations.

CAUTION: Total emissions from any facility or source shall not exceed major source levels prior to emission control installation. Major source levels are 10 TPY of any single HAP, 25 TPY of any combination of HAP or 100 TPY of any regulated pollutant. Dehydration unit emissions occurring prior to the installation of required controls will be determined using the GRI-GLYCalc model or other method approved by the Division based on the maximum lean glycol circulation rate and the actual reported gas production rate including any gas, which was routed through the dehydration unit during well completion operations.



BACT for Sources without P-BACT Requirements

For emission sources without PRESUMPTIVE BACT requirements, BACT shall be addressed when the uncontrolled source emits greater than or equal to 6 TPY VOC and HAPs for sources located in the **SWA** or 4 TPY VOC and HAPs for sources located in the **UGRB** or **JPAD/NPL**.

For these sources **EITHER** the emission source will be controlled using previously implemented BACT **OR** a BACT cost analysis will be performed and submitted with the application showing either:

control is not technically feasible (i.e., due to physical constraints the emissions cannot be controlled)

OR

control is not economically reasonable (i.e., based on a control cost analysis the “cost to control per ton of pollutant reduced” is uneconomical).

CAUTION: **BACT** may be required at lower levels and for other emissions and emission sources than those stated in this guidance, but as a minimum, **BACT** shall be considered when equal to or above these guidance emission levels. For example, operators installing pumping unit engines according to Guidance might be asked to submit a BACT analysis for the engine.

Multiple pieces of the same type of equipment are considered one emission source for permitting purposes.

For example, there are five oily rag burners at a facility located in the **SWA**. Uncontrolled emissions from the five burners shall be aggregated for permitting purposes. If total uncontrolled VOC emissions from the five burners are less than the development area specific threshold of 6 TPY, BACT requirements are met with no control. If total uncontrolled emissions from the five burners are greater than or equal to 6 TPY VOC and HAPs, emissions from all five burners shall be reduced to less than 6 TPY VOC and HAPs in order to meet BACT requirements or the applicant shall demonstrate controlling the emissions is not economically reasonable nor technically feasible.



Permit Applications

For **JPAD/NPL**, **UGRB** and **SWA** facilities, unless a permit is issued prior to start up, a C6 S2 Oil & Gas Production Facilities permit application shall be filed within 90 days after the First Date of Production for a new facility or Date of Modification of an existing facility. The application notifies the AQD that the new or modified facility has begun operation. It describes the facility process, equipment and associated emissions/emissions controls and serves as a form of certification by the owner that the Presumptive BACT requirements have been met.

Whether the application is being filed after construction under the Presumptive BACT process or prior to construction, the appropriate application forms, depending upon the facility equipment and operating scenario, need to be filled out. A complete application includes the following

- A cover letter stating the purpose of the application
- Equipment list for the facility
- A written process description and process diagram for the facility, including each air emission source and the operational parameters of each source (examples provided on pages 34 & 35)
- The appropriate IMPACT forms
 - Cover Sheet
 - Emission Unit Form for all new or modified equipment
 - Pollutant Emissions Form for each emission unit
 - Release Point Form for each emission unit
 - Control Equipment Form (where applicable)
- The appropriate additional documentation (examples include)
 - Emission Summary
 - BACT cost analysis
- Explanations or demonstrations of all methods used to calculate or estimate emissions for each emission source, including controlled and uncontrolled sources. Emission calculation methods are described later.
- All applicable and required attachments, including:
 - Input and output for emission models/software/process simulations
 - Equipment manufacturer's emissions information
 - Laboratory analyses used for emission models/software/process simulations or calculations including a description of sampling procedures and handling, sampling locations, sampling location parameters (i.e., pressure and temperature at sampling port)
- Any additional attachments or information necessary for complete review of the application



Permit Applications (cont.)

As of September 2, 2014, the New Source Review program is processing all air quality permit applications electronically through the IMPACT System. There are two acceptable methods to submit an application. Please choose just one of the methods below:

- Applications may be submitted through the IMPACT portal (<https://airimpact.wyo.gov>). Submittals through the IMPACT portal are sufficient and paper copies are not required.
- Two paper copies (one with an original signature) of each complete permit application.

The preferred method for filing the application is through the IMPACT portal.

For facilities constructed or modified under the **Presumptive BACT** process a complete C6 S2 application shall be submitted within **90 days** of the **First Date of Production**. In the event that the IMPACT portal is not functioning properly and prevents the submittal of the application within 90 days of First Date of Production, the applicant will need to contact the Division prior to the due date of the application to inform NSR of the issue and the applicant will need to provide documentation in the permit application showing the reason for the delayed submittal. Examples of acceptable documentation include a screen shot showing the issue or a copy of email correspondence between the applicant and the Division discussing the problem.

If not submitting through the IMPACT portal, download IMPACT application forms from the AQD website:

<http://deq.wyoming.gov/aqd/new-source-review/resources/application-forms/>

The oil and gas applications forms are contained in one Microsoft Excel file. The file name for the IMPACT application forms is “01 - AQD - NSR - Application Form”.

If you need assistance with the applications forms, contact the Wyoming Air Quality Division at **(307) 777-7391**.

Address written requests to: Wyoming Department of Environmental Quality
Air Quality Division
(see WDEQ website for current mailing address)
attn: O&G NSR Permitting*

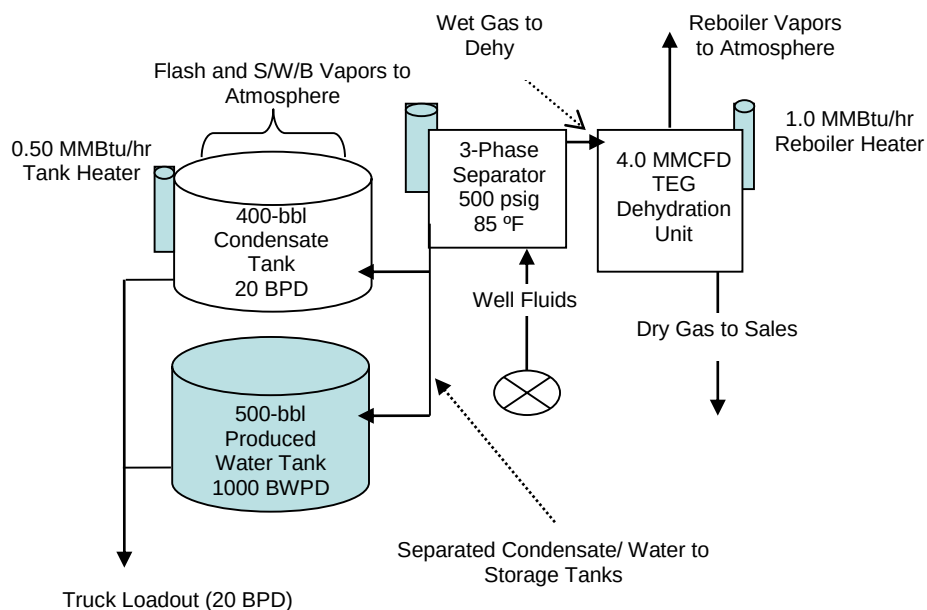
*To assist with the proper routing of the application and application materials, please make sure to address the materials to O&G NSR Permitting.

With the implementation of an electronic permitting system, the NOI process will no longer be utilized for new applications. Minor equipment installations and/or modifications that qualified for a NOI will now submit a complete application with the appropriate information listed on page 32. IMPACT forms and associated information are required for new or modified equipment.



Permit Applications (cont.)

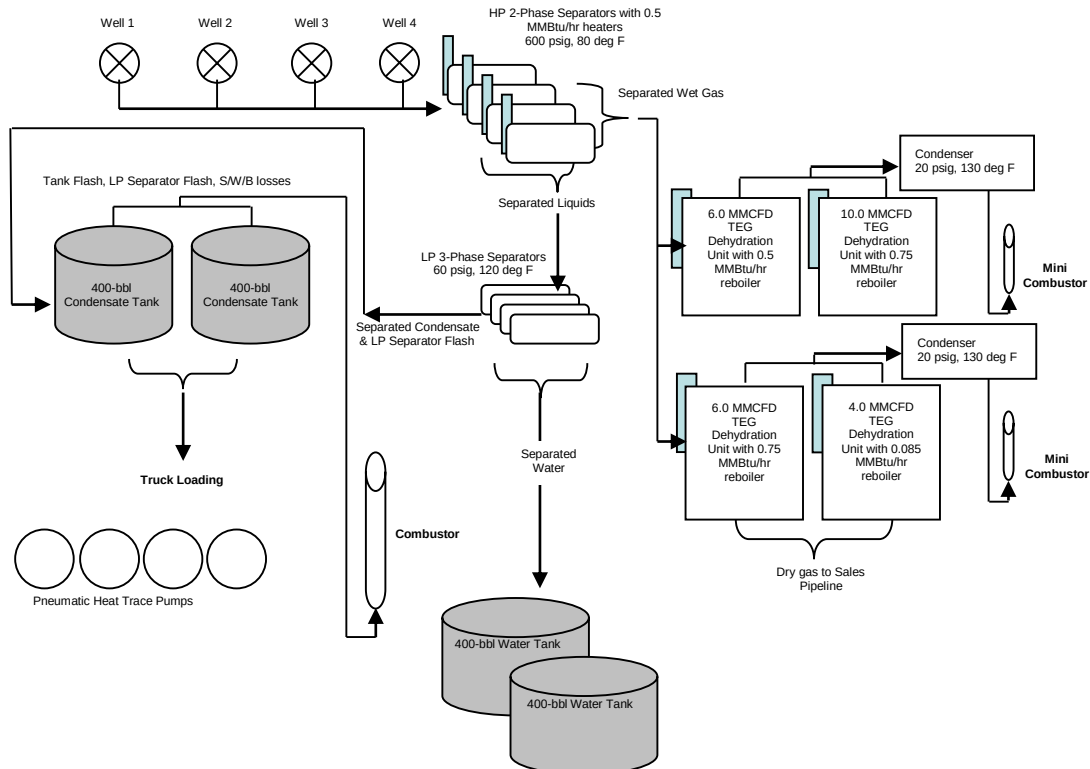
Example Process Diagram & Description



EXAMPLE: Air emission sources in the diagram are the condensate storage tank from which vapors are vented to the atmosphere, the dehydration unit reboiler still vent and the three natural gas-fired process heaters. Produced fluids are directed to the 3-phase separator for separation of condensate/water/gas. Wet gas is directed to the TEG dehydration unit for drying. Separated condensate and water are routed to the appropriate tanks for storage prior to being hauled from location via truck. Produced gas is used as burner fuel. Reboiler vapors and flash emissions are vented to the atmosphere along with S/W/B losses from the condensate tank.



Example Process Diagram & Description



EXAMPLE: Total well fluids from four wells flow to the 2-ph HP separators. Wet gas from the HP separators flows to the four dehydration units. Separated fluids from the 2-ph HP separators flows to the 3-ph LP separators. Separated condensate and water flows from the 3-ph LP separators to the storage tanks. Gas released in the 3-ph separators is routed to the condensate storage tanks. Tank vapors, including tank flash, gas from the 3-ph LP separators and S/W/B vapors are collected and directed to a 30-foot smokeless combustor. The temperature of the combustor is continually monitored and recorded using a SCADA (supervisory control and data acquisition) system. Reboiler still vents vapors flow through condensers. Condensed liquids are pumped to the condensate storage tanks. Non-condensable vapors flow to the 20-foot Mini-Combustors. The temperature of the Mini-combustors is continually monitored and recorded using a SCADA system. Pneumatic heat trace pumps operate 6 months per year using produced gas from the HP separators to operate. Vent lines from the pumps are routed into the condensate dump lines from the LP separators.

The process diagram does not need to be computer generated. A simple hand sketch is sufficient as long as the required information is included. The diagram does not need to be drawn to scale and does not need to represent the exact position of production equipment at the facility as long as the process description and operating scenario are clearly defined.



Permit Applications (cont.)

Upon receipt of a paper application, the Division must input the required application information into an electronic system (IMPACT) for processing. Once the paper application is processed, the Division sends the applicant a receipt letter. For electronic applications received via IMPACT, the Division simply issues a receipt letter after the application is received and a reviewer is assigned. The reviewer has up to 30 days to perform a completeness review to ensure adequate and correct information has been filed. If the application is deemed incomplete the reviewer will notify the applicant and request further information. Upon completeness the reviewer has 60 days to complete a technical review, write an application analysis and make any recommendations. During this process the decision to issue a permit or waiver takes place. If the decision is to issue a permit, the proposed permit, including compliance requirements, is published for a mandatory 30 day public comment period. If no comments are received the permit is issued once the public comment period ends. If comments are received these are addressed by the AQD. It is possible comments will warrant a public hearing. When this is the case, a final permit may be denied or delayed.

A minimum fee (\$464, subject to change) will be charged to each application. An hourly fee (\$58 per hour, subject to change) will be assessed for the time it takes AQD personnel to process the application. A bill will be sent to the applicant when the process is complete. Billing is handled as follows:

Initial billing (permits only) is assessed when a proposed permit is sent to public notice. The initial billing must be paid before AQD can issue a final permit.

Final billing is assessed for waivers and permits after these are issued.

Contact the Division for the current hourly rate.

NOTE: The Presumptive BACT permitting process may not be used for sour gas (H₂S) production facilities unless the only emissions of H₂S will be those associated with fugitive losses from valves, fittings, surface piping and pneumatic devices, etc. If there will be H₂S emissions associated with vented gas or tank vapors or if sour gas will be flared the applicant shall contact the Division for permitting guidance prior to construction.

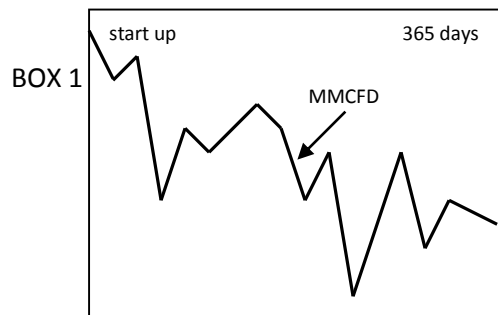
No internal combustion compressor engines or generator engines may be installed under the Presumptive BACT process.

No pumping unit engines greater than 50 Hp may be installed under the Presumptive BACT permitting process. Such engines shall be permitted prior to installation.



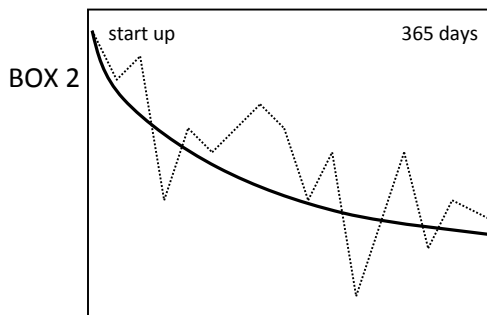
The 0.6 decline factor

The first year daily production rates are represented by the jagged line **BOX 1**. The area under the line represents the total actual production volume for the first year. It is difficult to calculate the total volume under the jagged line so it is smoothed out **BOX 2** using statistical methods.

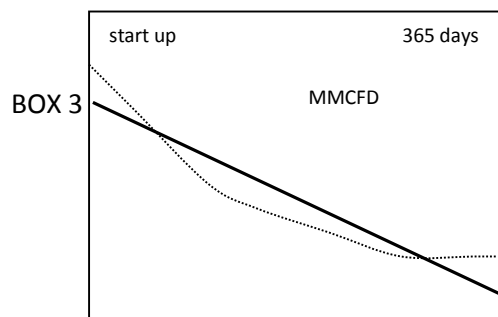


EXAMPLE - actual daily gas production rate vs time

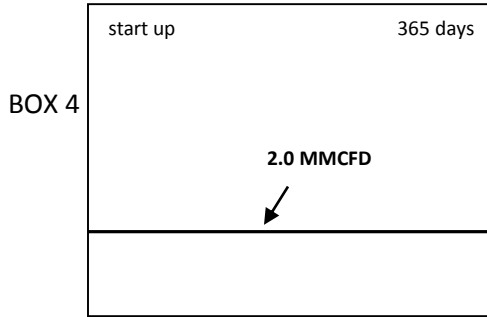
Actual production during the first year is represented by the area under the jagged line which ultimately turns out to be ≈ 730 MMCF.



The jagged line representing daily production is “smoothed” out using statistical methods.



The “smoothed” curve in BOX 2 is “straightened” out using mathematical methods.



“leveled” out, projected daily gas production rate vs time

Total projected production for the first year is represented by the area under the straight line
 $2 \text{ MMCFD} \times 365 \text{ days} = 730 \text{ MMCF}$

First year projected emissions are based on 730 MMCF of produced gas.

The smoothed curve is “straightened” out in **BOX 3**, then “leveled” out in **BOX 4**. Now the total production for the first year is represented by the area under the line in **BOX 4**, which is easily calculated. Production curves from a large sampling of Wyoming wells indicate the average well declines by 80% during the first year. That 80% decline is represented by the level line in **BOX 4** after the first 30-day average production rate is multiplied by 0.6. For the first month the well makes an average 3.333 MMCFD. With 80% decline during the first year, the well will make 0.667 MMCFD at the end of the first year ($3.333 - 0.8(3.333) = 0.667$). Then the average daily production rate over 365 days is $(3.333 + 0.667)/2 = 2.0$ MMCFD, which is the same as $3.333 \times 0.6 = 2.0$.



Pumping Unit Engines

A pumping unit engine is an engine used to provide electrical or mechanical energy to a pump in order to produce a well.

This Guidance does not apply to compressor engines, engines used for vapor recovery, or pumping unit engines greater than 50 Hp.

This Guidance replaces the March 9, 2012 Pumping Unit Engine Emissions Policy.

Historically, AQD has allowed the installation of pumping unit engines at oil & gas production facilities as part of the Guidance. Engines were allowed to be installed prior to permit issuance, provided the engine was site rated for less than 50 Hp and emitted less than 5 TPY of NO_x.

The Guidance does not however preclude the Division from asking the applicant to submit a Best Available Control Technology (BACT) analysis to determine if emissions from the engine are technically feasible and economically reasonable to control. As demonstrated in the March 9, 2012 Pumping Unit Engine Emissions Policy, BACT is a moving target and relying on an emissions threshold of 5 TPY NO_x was no longer considered BACT for pumping unit engines less than 50 Hp. AQD will continue to allow installation of pumping unit engines prior to obtaining a permit provided the engine meets BACT and the requirements listed below.

Installation of pumping unit engines site rated for 50 Hp or less is allowed provided the engine meets NO_x emissions of 2.0 g/hp-hr and CO emissions of 3.0 g/hp-hr.

Initial and/or periodic emissions testing and monitoring of the pumping unit engine may be established in the permit or permit waiver.

APPENDIX A

EMISSION CALCULATIONS

Emissions from processes and equipment, which shall be accounted for and reported by applicants FOR ALL O&G PRODUCTION FACILITIES are:

Emission Unit or Process	Associated Emissions
storage tanks (flashing & S/W/B losses)	VOC HAP
pressurized vessels (flashing losses)	VOC HAP
dehydration units (reboiler still vents & glycol flash tanks)	VOC HAP
natural gas fired burners, heaters, flares	VOC NO _x CO
natural gas operated pneumatic controllers/pumps	VOC HAP
fugitives	VOC HAP
natural gas fired engines	NO _x CO VOC
truck load out	VOC HAP

AP-42 EMISSION FACTORS

Throughout this Guidance reference is made to AP-42 emission factors. The complete AP-42 compilation may be downloaded from <https://www3.epa.gov/ttn/chief/ap42/index.html>.

STORAGE TANK EMISSIONS

Flashing and Standing/Working/Breathing (S/W/B) losses are the terms for emissions which occur when hydrocarbon liquids are exposed to temperature and pressure changes (i.e., from separator pressure and temperature to storage tank pressure and temperature) causing hydrocarbon vapors to be released from the liquids. The vapors may contain VOCs, HAPs and H₂S.

Software is available for modeling these emissions. Models accepted by the Air Quality Division are those using Peng-Robinson or S-R-K methods based on widely accepted principals of behavior for hydrocarbon vapors and liquids. Some common software programs for estimating these emissions are PROMAX, HYSIM, HYSYS, K-FLASH, PROSIM and API E&P TANKS (v2.0 and higher). The models require input detailing chemical properties of the fluids handled and physical operating parameters of the system(s) and production equipment. Output from the models includes volumes, rates and chemical components of the individual process streams from tanks and pressurized vessels.

Emissions from storage tanks may also be physically measured. In order to do so all tank valves, hatches, relief devices, leaks, etc. shall be sealed. Tank vapors shall only be allowed to exit the tank through a metered outlet. Usually this requires a meter capable of measuring low volumes. The measurement period shall last long enough to capture a representative tank vapor volume. An extended hydrocarbon analysis of the vapors shall be obtained along with the vapor volume.

MEASURED TANK FLASH EMISSIONS – EXAMPLE CALCULATION

The tons per year of VOC and HAP emissions associated with tank flashing are calculated as follows:

Given: Condensate tank vapors = 1000 scf/day
VOC weight % = 20
HAP weight % = 5
Condensate vapor molecular weight = 20 lb/lb-mol

TPY total flash emissions = $1000 \text{ scf/day} \times (1 \text{ lb-mol}/379 \text{ scf}) \times (20 \text{ lb/lb-mol}) \times (\text{ton}/2000 \text{ lb}) \times (365 \text{ days/year}) = 9.6 \text{ TPY}$

TPY total VOC emissions = $9.6 \text{ TPY} \times (20 \text{ weight \% VOC} / 100) = 1.9 \text{ TPY VOC}$

TPY total HAP emissions = $9.6 \text{ TPY} \times (5 \text{ weight \% HAP} / 100) = 0.5 \text{ TPY HAP}$

S/W/B losses

Not all software programs include tools for estimating S/W/B losses. There is free software available from the EPA named EPA TANKS. The most recent available version of EPA TANKS may be downloaded from the EPA website at <https://www3.epa.gov/ttn/chief/software/tanks/index.html>.

PRESSURIZED VESSELS

Whenever vapors from a pressurized vessel (separator, treater, FWKO, flash separator, gunbarrel, gas boot, etc) are released to the atmosphere, other than during times of emergency or upset conditions, emissions associated with those vapors shall be accounted for.

The same flash emission models mentioned above, for tank flash emissions, are often used to estimate emissions from pressurized vessels. Again, an extended hydrocarbon analysis of the liquids involved and actual operational conditions of the production equipment are necessary as input for the models.

Even when vapors from a pressurized vessel are collected for use as process burner fuel or fuel for an IC engine, for example, emissions associated with the total vapors shall be accounted for when considering potential emissions from a facility. If the volume and rate of vented vapors are known and an extended hydrocarbon analysis is available, associated emissions may be calculated in the same manner as described on Page 39 (calculation of flash emissions). If these are not available, the volumes shall be measured and analyzed in order to perform the calculations and determine associated emissions.

DEHYDRATION UNIT EMISSIONS

Air pollutants, mostly VOCs and HAPs, are associated vapors released from reboiler still vents and glycol flash separators. To estimate these emissions the GRI-GLYCalc v4.0 or higher model or other approved method is used. This relatively inexpensive software was created by the Gas Research Institute (GRI) for determining optimal operating parameters for dehydration units and is available from the Gas Technology Institute (GTI) with a website address of <http://sales.gastechnology.org/>.

Input for the model includes an extended hydrocarbon analysis of wet gas sampled upstream of the contact tower, actual operating parameters of all associated equipment (i.e., reboiler still vent temp., flash separator temp., dry gas flow rate, glycol recirculation rate, condenser, etc) and physical properties of the dry and wet gas streams. The model provides an estimate of individual emission components and the rates of vapor and liquid streams exiting each process vent of a dehydration unit. When submitting a GRI-GLYCalc

model it is only necessary to submit the INPUT SUMMARY, EMISSIONS SUMMARY, CONDENSER VENT OUTPUT (if applicable) and FLASH TANK OUTPUT (if applicable).

NATURAL GAS FIRED HEATERS (external combustion equipment)

NO_x, CO and VOC emissions from process unit heaters should be calculated using the emission factors (EF) below from EPA AP-42, Tables 1.4-1, 1.4-2 and 1.5-1. The following lists these factors:

Emission Factors for Industrial and Commercial Boilers

Pollutant	Butane Gas ¹ (0.3 to 100 MMBtu/hr heat input)	Propane Gas ² (0.3 to 100 MMBtu/hr heat input)	Natural Gas ³ <100 MMBtu/hr heat input	Natural Gas ³
NO _x ⁴	15 lb/1000 gal	13 lb/1000 gal	0.098 lb/MMBtu	100 lb/MMcf
CO ⁴	8.4 lb/1000 gal	7.5 lb/1000 gal	0.082 lb/MMBtu	84 lb/MMcf
TOC ^{4,5}	1.1 lb/1000 gal	1.0 lb/1000 gal	0.010 lb/MMBtu	11 lb/MMcf

¹ Based on an average heating value of 102×10^6 Btu/1000 gallons of Butane.

² Based on an average heating value of 91.5×10^6 Btu/1000 gallons of Propane.

³ Based on an average heating value of 1020 Btu/SCF of natural gas.

⁴ The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factors by the ratio of the heating value of the actual gas used to the average heating values listed
Converted EF = (EF from table above $\times$ (actual heat value/heat value in table)).

⁵ VOC emissions may be determined by multiplying the calculated TOC (total organic compounds) emission rate by the weight percent of VOC compounds in the actual fuel gas stream.

HEATER EMISSIONS - EXAMPLE CALCULATION

Given: Separator heater rating = 0.5 MMBtu/hr
Gas Heating Value = 1300 Btu/scf
VOC weight % = 20
Annual operating hours = 8760
NO_x EF = 100 lb/MMcf
CO EF = 84 lb/MMcf
TOC EF = 11 lb/MMcf

NO_x emissions = (0.5 MMBtu/hr) $\times$ (100 lb/MMcf) $\times$ (1300 Btu/1020 Btu) $\times$ (1 scf/1020 Btu) $\times$ (8760 hr/yr) $\times$ (ton/2000 lb) = 0.27 TPY NO_x

For CO emissions, the same calculation is used except the EF is 84 lb/MMcf.

VOC emissions = $0.5 \times 11 \times (1300/1020) \times 1/1020 \times 8760/2000 \times (20\% \text{ VOC}/100) = 0.006 \text{ VOC TPY}$ VOC ← INSIGNIFICANT at less than 0.1 TPY

FLARES

The NO_x and CO emissions for flares should be based on **0.14 lb NO_x/MMBtu and 0.035 lb CO/MMBtu** (Emission factors from Section 4 of EPA Document “Preferred and Alternative Methods for Estimating Air Emissions from Oil and Gas Field Production and Processing Operations”) and the reported fuel usage based heat input. VOC and HAP emissions from flaring should be based upon the guaranteed destruction efficiency of the flare. Reported flared gases shall include pilot gas with heat content and flared gas with average estimated heat content. The rationale for using these factors as opposed to AP-42 factors for flares is that the flare factors are believed to be only applicable to chemical plant type flares engaged in burning low BTU gases. The gases typically burned in flares in Wyoming contain more than 900 Btu/scf and emissions are expected to be closer to the AP-42 factors for NO_x and CO from gas fired heaters and boilers greater than 10 MMBtu/hr.

FLARE EMISSIONS - EXAMPLE CALCULATIONS – CONDENSATE TANK FLASH

Given: Total waste gas = 125 scf/hr
Gas heating value = 1350 Btu/scf

$$\text{NO}_x \text{ emissions} = (125 \text{ scf/hr}) \times (1350 \text{ Btu/scf}) \times (0.14 \text{ lb NO}_x/\text{MMBtu}) \times (\text{MMBtu}/10^6 \text{ Btu}) \times (8760 \text{ hr/yr}) \times (1 \text{ ton}/2000 \text{ lb}) = 0.1 \text{ TPY NO}_x$$

FLARE PILOT EMISSIONS

Given: Flare pilot gas = 5 scf/min
Gas heating value = 1000 Btu/scf

$$\text{NO}_x \text{ emissions} = (5 \text{ scf/min}) \times (1000 \text{ Btu/scf}) \times (0.14 \text{ lb NO}_x/\text{MMBtu}) \times (\text{MMBtu}/10^6 \text{ Btu}) \times (60 \text{ min/hr}) \times (8760 \text{ hr/yr}) \times (1 \text{ ton}/2000 \text{ lb}) \\ = 0.18 \text{ TPY NO}_x$$

For CO emissions the same calculations are used except the EF for CO is 0.035 lb/MMBtu.

FLARE EMISSIONS EXAMPLE CALCULATION – DEHYDRATION UNITS

Given: Glycol flash separator vapors = 25 scf/min
Reboiler still vent vapors = 5 scf/min
Total waste gas = 30 scf/min (25 scf/min glycol flash vapors + 5 scf/min reboiler still vent vapors)
Gas Heating Value = 1050 Btu/scf (**assume at least 1000 BTU/SCF if the heat content is unknown**)

$$\text{NO}_x \text{ emissions} = (30 \text{ scf/min}) \times (1050 \text{ Btu/scf}) \times (0.14 \text{ lb NO}_x/\text{MMBtu}) \times (\text{MMBtu}/10^6 \text{ Btu}) \times (60 \text{ min/hr}) \times (8760 \text{ hr/yr}) \times (1 \text{ ton}/2000 \text{ lb}) \\ = 1.1 \text{ TPY NO}_x$$

For CO emissions the same calculations are used except the EF for CO is 0.035 lb/MMBtu.

PNEUMATIC PUMPS

If a pneumatic pump uses natural gas as the motive gas, the pump will release VOC and HAP emissions each time it strokes since all motive gas is vented by the pump. To determine emissions from the pump, manufacturer’s information regarding gas usage shall be known as well as the hydrocarbon composition of the motive gas.

PNEUMATIC PUMP EMISSIONS - EXAMPLE CALCULATION

A Texsteam Series MX pump is used to circulate hot glycol in heat trace lines. The pump moves 0.15 gallons per 40 strokes and is currently stroking at 20 strokes per minute (spm). The pump requires 24 scf for each gallon of glycol pumped. The pump motive gas weighs 20 lb/lb-mol and contains 50 wt% VOCs and 30 wt% HAPs.

Pump usage/vent rate = (20 strokes/min) × (0.15 gallons/40 strokes) × (24 scf/gallon) = 1.8 scf/min

VOC emissions = (1.8 scf/min) × (20 lb/lb-mol) × (lb-mol/379 scf) × (ton/2000 lb) × (525600 min/yr) × (50 wt% VOC/100) = 12.5 TPY VOC

PNEUMATIC CONTROLLERS

Emissions from continuous bleed pneumatic controllers shall be based on the manufacturer-certified bleed rates. Emissions from intermittent vent controllers shall be based on the volume of gas required for actuation and the applicant's best engineering estimate of the frequency of actuations.

TRUCK LOADING

VOC emissions from loading oil or condensate into tank trucks should be estimated using the following formula with data from AP-42 tables.

$$L_L = 12.46 \times S \times P \times M/T$$

Where: L_L = loading loss, pound per 1,000 gallons of liquid loaded (lb/1000 gal)

S = a saturation factor (See Table 5.2-1 below)

P = true vapor pressure of liquid loaded (psia)

M = molecular weight of tank vapors (lb/lb-mol)

T = temperature of bulk liquid loaded (°R) (°R = °F + 460)

"S" values are obtained from Table 5.2-1.

"M" and "N" values are obtained from Table 7.1-2.

Table 5.2-1 Saturation (S) Factors for Calculating Petroleum Liquid Loading Losses

Cargo Carrier	Mode of Operation	"S" Factor
tank trucks and rail tank cars	submerged loading of a clean cargo tank	0.50
	submerged loading: dedicated normal service	0.60
	submerged loading: dedicated vapor balance service	1.00
	splash loading of a clean cargo tank	1.45
	splash loading: dedicated normal service	1.45
	splash loading: dedicated vapor balance service	1.00

Table 7.1-2 Properties of Selected Petroleum Liquids

Only crude oil properties are supplied here. The full table of values can be found in AP-42, Table 7.1-2)

petroleum liquid	vapor molecular weight at 60°F (lb/lb-mol)	condensed vapor density at 60°F (lb/gal)	liquid density at 60°F (lb/gal)	true vapor pressure (psi) at various temperatures in °F						
				40	50	60	70	80	90	100
	"M"			"P"						
Crude Oil RVP 5	50	4.5	7.1	1.8	2.3	2.8	3.4	4.0	4.8	5.7

TRUCK LOADOUT - EXAMPLE CALCULATION

Given: Condensate loaded = 360 bbl crude/month

S = 0.6

P = 2.3 psi

M = 50 lb/lb-mol

T = 50

$$L_L = \frac{(12.46) \times (0.60) \times (2.3 \text{ psi}) \times (50 \text{ lb/lb-mol})}{(50^\circ\text{F} + 460)} = 1.69 \text{ lb/1000 gal}$$

$$\text{Loading losses (TPY)} = (1.69 \text{ lb/1000 gal}) \times (\text{annual sales of } 360 \text{ bbl/mo}) \times (12 \text{ mo/yr}) \times (42 \text{ gal/bbl}) \times (\text{ton/2000 lb}) = 0.15 \text{ TPY}$$

Capture efficiencies are determined on a case-by-case basis for controlled sites.

FUGITIVE EMISSIONS

The easiest way to calculate total hydrocarbon fugitive emissions is to multiply the number of components at a site by the EPA Average Emissions Factors shown in the tables below. The first table lists the average emission rates of **total hydrocarbon** (THC) to be assumed for all components in hydrocarbon service installed at a site. The factors are current as of June 15, 1996 and given in pounds per component - day (lb/component-day). The second table lists speciated rates.

The only information needed for this method is a count or estimate of the number of flanges, connectors (other than flanges), open-ended lines, pumps, valves and "other" components at the site grouped by stream (gas, light oil, heavy oil, water/oil). The number of components can be determined by either counting them in the field or by estimating them.

**EPA Average Emission Factors for Total Hydrocarbon (THC) Emissions
From O&G Production Operations**
(lb/component-day)

equipment type	equipment service category			
	gas	heavy oil ($< 20^{\circ}\text{API}$)	light oil ($> 20^{\circ}\text{API}$)	water/light oil ¹
connector	.011	.0004	.011	.0058
flange	.021	.000021	.0058	.00015
open ended line	.11	.0074	.074	.013
other ²	.47	.0017	.4	.74
pump	.13	not available	.69	.0013
valve	.24	.00044	.13	.0052

SOURCE: US EPA Bulletin Board (Leaks_OG.WP5; 8/9/1995)

¹ The water/light oil emission factors apply to water streams in light oil service with water content between 50% and 99%. For streams with water content $> 99\%$ the emission rate is considered negligible.

² The "other" equipment type includes compressor, pressure relief valves, diaphragms, drains, dump arms, hatches, instruments, meters, polished rods and vents.

NOTE: The emission factors in the table above are not intended to be used to represent emissions from components that are improperly designed (e.g., enardo valves over pressurizing, failure of thief hatches to reseal after over pressurizing) or equipment not maintained properly (e.g., thief hatch left open). For example, emissions from an enardo valve on a condensate tank vent line, operating in the full or partially open position due to excessive tank vapor pressure that exceeds the pressure setting of the enardo valve, are not considered to be fugitive emissions.

Speciated hydrocarbon emission rates can be estimated by multiplying the total hydrocarbon emission rates obtained from the table above by actual measured weight fractions. If measured data is not available, contact the Division for further guidance.

FUGITIVE EMISSIONS - EXAMPLE CALCULATION

Given: 25 valves in light oil service

THC emission factor = 0.13 lb/component-day

VOC weight fraction = 0.292

HAP weight fractions = $0.02430 + 0.00027 + 0.00075 + 0.00017 + 0.00036 = 0.0259$

VOC emissions = $25 \text{ valves} \times 0.13 \text{ lb THC/valves-day} \times 1 \text{ ton/2000 lb} \times 365 \text{ day/hr} \times 0.292 = 0.17 \text{ TPY VOC}$

HAP emissions = $25 \text{ valves} \times 0.13 \text{ lb THC/valves-day} \times 1 \text{ ton/2000 lb} \times 365 \text{ day/yr} \times 0.0259 = 0.015 \text{ TPY total HAPs}$

INTERNAL COMBUSTION PUMPING UNIT ENGINE EMISSIONS

The method for calculating engine emissions is to use emission factors provided by the engine manufacturer, the maximum site-rated horsepower and the annual operating hours.

PUMPING UNIT ENGINE EMISSIONS - EXAMPLE CALCULATION

Given: Manufacturer's NO_x emission factor = 2 g/hp-hr
Maximum site-rated horsepower = 250 hp
Annual operating hours = 8760

NO_x emissions = (2.0 g/hp-hr) × (250 hp) × (8760 hr/yr) × (ton/2000 lb) × (1 lb/453.6 g) = 4.8 TPY

For CO and VOC emissions the same calculations are used except the manufacturer's EF for CO and VOC are used.

CONVERTING MOLE PERCENT TO WEIGHT PERCENT

Many emission estimation and calculation methods require weight percent to be used, rather than mole percent. Most lab analyses list gas constituents in mole percent, however you can request the lab provide both mole and weight percent.

You may download the Excel spreadsheet to convert mole percent to weight percent, at <http://deq.wyoming.gov/aqd/new-source-review/>.

APPENDIX B

DEFINITIONS

Air Contaminant – Shall mean dust, fumes, mist, smoke, other particulate matter, vapor, gas or any combination of these; but shall not include steam or water vapor.

Air pollutants – Also known as criteria pollutants, Air pollutant emissions which have ambient air standards associated with them. Air pollutants include such emissions as volatile organic compounds (VOC), nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO₂), hazardous air pollutants (HAP) and others.

Average Daily Production – The qualified maximum total production of domestic crude petroleum and petroleum condensates including natural gas liquids produced from a well during a certain period of time (i.e. 1-month, 1-year) divided by the number of calendar days in the certain period during which the well produced. For example, the average 30-daily condensate production rate for well ABC is the qualified maximum total condensate production during the 30-day period $x(\text{BBL}) \div 30(\text{days}) = y(\text{BPD})$. If well ABC only produced 5 days out of the 30-day period, then the average daily condensate production rate for the well is $x(\text{BBL}) \div 5(\text{days}) = y(\text{BPD})$.

Closed System – A vessel (treater, separator), pipeline, sales line, gathering line, collection line, field gas supply or distribution line or any other vessel or line from which no vapors or liquids can exit through open lines, holes, vents or valves unless those lines, holes, vents or valves are connected to another closed system or to a source of continual and complete combustion, unless the vent or valve is a relief device that is designed and intended to open only during emergency situations.

Completion – An oil well shall be considered completed when the first new oil is produced through wellhead equipment into lease tanks from the producing interval after the production string has been run. A gas well shall be considered completed when the well is capable of producing gas through wellhead equipment from the producing zone after the production string has been run.

Condensate – Hydrocarbon liquid separated from natural gas that condenses (becomes liquid) due to changes in temperature, pressure, or both, and remains liquid at standard conditions.

Custody Transfer – The transfer of produced petroleum and/or condensate, after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation.

Division – The Wyoming Department of Environmental Quality, Air Quality Division.

First Date of Production – The date permanent production equipment is in place and product is consistently flowing to sales lines, gathering lines or storage tanks. Production occurring during well completion activities which is routed to temporary production equipment is considered to occur prior to the First Date of Production. If extended periods of time pass between zone completions but production from initially completed zones is consistently flowing to permanent production equipment, the First Date of Production is the date when production from the initial zones began consistently flowing to the permanent production equipment, even though more zones will be completed later.

Fugitive Emissions (Fugitives) – Air emissions which result from gas vapors escaping through and around seals, packing, gaskets, threads, and other such pressure sealing connections.

Gas – All natural gases and all hydrocarbons not defined as oil.

Gas Well – A well, the principal production of which, at the mouth of the well, is gas, as defined by the Wyoming Conservation Law.

Grandfathered – A facility, installation or site which was built or in service before May 29, 1974 and that has not been physically or operationally changed, causing an increase in any pollutant (to which any state standard applies) or causing the emission of a new pollutant. (Modifications which could eliminate grandfather status are increasing production rate by fracturing, acidizing, recompletion of a zone, change in artificial lift methods, bringing new wells into a central battery or a waterflood response. Also such things as installing an engine, increasing horsepower, change in burner ratings. This list is not all inclusive and judgment should be used to determine appropriate status.)

HAP – Pollutants identified in Section 112(b) of the Clean Air Act. Typical hazardous air pollutants include benzene, toluene, ethyl-benzene, xylene, n-hexane, formaldehyde, methanol and others.

Low bleed pneumatic controller – A continuous bleed or intermittent vent device that emits less than 6 scf/hr. The Division considers controllers that are operated in accordance with manufacturer design specifications and have a manufacturer-designed emission rate that satisfies the 6 scf/hr threshold, to meet the definition of low bleed pneumatic controller.

Major Emitting Facility – A facility which either has the potential to emit 250 TPY or more of any one regulated air pollutant or is a named facility and has the potential to emit 100 TPY or more of any one regulated air pollutant. For a facility located in a non-attainment area, the definition of major emitting facility is subject to change based on the area's classification. See WAQSR Chapter 6, Section 13.

Major Source – A source which emits either 100 TPY or more of a regulated air pollutant, 10 TPY or more of a hazardous air pollutant, or 25 TPY or more of the total hazardous air pollutants.

Modified Facility – An existing facility becomes modified once production streams or production equipment associated with another well or wells is added to or tied into it. The date modification occurs to an existing facility is the First Date of Production for the added well or the date the production streams associated with an additional well or wells are tied into equipment at the existing facility.

Examples of facility modifications not involving new wells or added production from other wells are:

- Increasing the production rate above the average daily condensate/oil or gas production rate for the previous twelve (12) calendar months by fracturing, acidizing, recompletion of a current production zone, change in artificial lift methods, or a CO₂ flood/water flood response.
- Completing in additional production zones resulting in an increase in production above the average daily condensate/oil or gas production rate for the previous twelve (12) calendar months and/or emissions at the facility.
- Existing production equipment is replaced with larger equipment, resulting in increased potential or actual emissions.

Note: When equipment with Presumptive BACT requirements is added to a facility but doesn't trigger the definition of a modified facility, the Presumptive BACT requirements only have to be met for the new equipment (i.e., a pneumatic methanol pump is added, this new pump would have to either be controlled or solar, air or electric).

Oil – Crude petroleum oil and any other hydrocarbons, regardless of gravities, which are produced at the well in liquid form by ordinary production methods, and which are not the result of condensation of gas before or after it leaves the reservoir.

Oil Well – A well, the principal production of which, at the mouth of the well, is oil, as defined by the Wyoming Conservation Law.

PAD – A PAD facility is a location where more than one well and/or associated production equipment are located, where some or all production equipment is shared by more than one well or where well streams from more than one well are routed through individual production trains located at the same or contiguous and adjacent location. If the production streams or production equipment associated with one or more wells is added to an existing single well facility, that location is then considered to be a PAD facility. A single well becomes a multiple well or PAD facility upon the First Date of Production of an additional well at the location or on the day production streams associated with an additional well or wells from separate locations are routed to the single well facility. A tank battery is not considered a PAD facility.

Potential to Emit – The maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is enforceable by the EPA and the Division.

Recompletion – Any downhole operation in an existing oil or gas well that is conducted to establish production of oil or gas from any geological interval not currently completed or producing in said existing oil or gas well.

Single Well Facility – A single well facility is one where production equipment is associated with only one well. A single well becomes a multiple well or PAD facility upon the First Date of Production of an additional well at the location or on the day production streams associated with an additional well or wells from separate locations are routed to the single well facility.

Spud – The commencement of operations for the first boring of a hole for the drilling of an oil, gas or injection well. This includes setting conductor casing.

Synthetic Minor – “Synthetic Minor” sources are sources that do the following types of things to limit emission rates below 100 TPY: 1) limit operating hours of a source or 2) limit production rates such that source emissions are less than 100 TPY.

Tank Battery – An oil production facility with little to no produced gas that is comprised mainly of separators, heaters, and tanks. The facility does not use dehydration units. The API gravity of the produced oil is no higher than 25°.

VOC – Volatile organic compound means any organic compound which participates in atmospheric photochemical reactions; typically considered C_3^+ or Non-methane/ethane hydrocarbon vapors.

VOC Weight Percent – This is the weight of the volatile organic compounds, expressed as a percent, as compared to the total weight of the compounds in a gas stream. (This should not be confused with the volume or mole percent of a gas stream, which is usually how it is expressed in a lab analysis of a gas.)

Wildcat Well – Any oil or gas well designated as a wildcat well by the Wyoming Oil and Gas Conservation Commission. Wildcat wells are wells outside known fields or new wells which are determined by the Commission to have discovered oil or gas in a pool not previously proven productive.

Workover – Any downhole operation in an existing oil or gas well that is designed to sustain, restore or increase the production rate or ultimate recovery in a geologic interval currently completed or producing in said existing oil or gas well. Workover includes but is not limited to: acidizing, reperforating, fracture treating, sand/paraffin removal, casing repair, squeeze cementing or setting bridge plugs to isolate water productive zones from oil or gas productive zones or any combination thereof. Workover does not mean the routine maintenance, repair or replacement of downhole equipment such as rods, pumps, tubing, packers or other mechanical devices.

Worst case – A situation allowed in air permitting in the State of Wyoming where a facility, site or source (which is representative of all the facilities, sites or sources within a designated field area) may be used to represent the worst air emissions for the field area sources.

Wyoming Environmental Quality Act – Wyoming Statute, Title 35 “Public Health and Safety”, Chapter 11 “Environmental Quality” which provides the authority for the rules and regulations of the Air Quality Division.

Zero bleed controller – Electric, air-driven, or solar powered controller that does not rely on natural gas to actuate.

TITLE 20 ENVIRONMENTAL PROTECTION
CHAPTER 2 AIR QUALITY (STATEWIDE)
PART 50 OIL AND GAS SECTOR – OZONE PRECURSOR POLLUTANTS

20.2.50.1 ISSUING AGENCY: Environmental Improvement Board.
[20.2.50.1 NMAC – N, XX/XX/2021]

20.2.50.2 SCOPE: This Part applies to sources located within areas of the state under the board's jurisdiction that, as of the effective date of this rule or anytime thereafter, are causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated and based on data from one or more department monitors. Once a source becomes subject to this rule, the requirements of the rule are irrevocably effective unless the source obtains a federally enforceable air permit limiting the potential to emit to below such applicability thresholds established in this Part.
[20.2.50.2 NMAC – N, XX/XX/2021]

20.2.50.3 STATUTORY AUTHORITY: Environmental Improvement Act, Section 74-1-1 to 74-1-16 NMSA 1978, including specifically Paragraph (4) and (7) of Subsection A of Section 74-1-8 NMSA 1978, and Air Quality Control Act, Sections 74-2-1 to 74-2-22 NMSA 1978, including specifically Subsections A, B, C, D, F, and G of Section 74-2-5 NMSA 1978 (as amended through 2021).
[20.2.50.3 NMAC - N, XX/XX/2021]

20.2.50.4 DURATION: Permanent.
[20.2.50.4 NMAC - N, XX/XX/2021]

20.2.50.5 EFFECTIVE DATE: Month XX, 2021, except where a later date is specified in another Section.
[20.2.50.5 NMAC - N, XX/XX/2021]

20.2.50.6 OBJECTIVE: The objective of this Part is to establish emission standards for volatile organic compounds (VOC) and oxides of nitrogen (NO_x) for oil and gas production, processing, and transmission sources.
[20.2.50.6 NMAC - N, XX/XX/2021]

20.2.50.7 DEFINITIONS: In addition to the terms defined in 20.2.2 NMAC - Definitions, as used in this Part, the following definitions apply.

A. "Approved instrument monitoring method" means an optical gas imaging, United States environmental protection agency (U.S. EPA) reference method 21 (RM21) (40 CFR 60, Appendix B), or other instrument-based monitoring method or program approved by the department in advance and in accordance with 20.2.50 NMAC.

B. "Auto-igniter" means a device that automatically attempts to relight the pilot flame in the combustion chamber of a control device in order to combust VOC emissions, or a device that will automatically attempt to combust the VOC emission stream.

C. "Bleed rate" means the rate in standard cubic feet per hour at which natural gas is continuously or intermittently vented from a pneumatic controller.

D. "Calendar year" means a year beginning January 1 and ending December 31.

E. "Centrifugal compressor" means a machine used for raising the pressure of natural gas by drawing in low-pressure natural gas and discharging significantly higher-pressure natural gas by means of a mechanical rotating vane or impeller. Screw, sliding vane, and liquid ring compressor is not a centrifugal compressor.

F. "Closed vent system" means a system that is designed, operated, and maintained to route the VOC emissions from a source or process to a process stream or control device with no loss of VOC emissions to the atmosphere.

G. "Commencement of operation" means for an oil and natural gas well sithead, the date any permanent production equipment is in use and product is consistently flowing to a sales lines, gathering line or storage vessel from the first producing well at the stationary source, but no later than the end of well completion operation.

H. "Component" means a pump seal, flange, pressure relief device (including thief hatch or other

opening on a storage vessel), connector or valve that contains or contacts a process stream with hydrocarbons, except for components where process streams consist solely of glycol, amine, produced water or methanol.

I. “Connector” means flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, pipe components (such as elbows, reducers, “T’s” or valves) to each other; or a pipe line to a piece of equipment; or an instrument to a pipe, tube or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this Part.

J. “Construction” means fabrication, erection, installation or relocation of a stationary source, including but not limited to temporary installations and portable stationary sources.

K. “Custody transfer” means the transfer of oil or natural gas after processing or treatment in the producing operation, or from a storage vessel or automatic transfer facility or other processing or treatment equipment including product loading racks, to a pipeline or any other form of transportation.

L. “Control device” means air pollution control equipment or emission reduction technologies that thermally combust, chemically convert, or otherwise destroy or recover air contaminants. Examples of control devices include but are not limited to open flares, enclosed combustion devices (ECDs), thermal oxidizers (TOs), vapor recovery units (VRUs), fuel cells, condensers, [air fuel ratio controllers \(AFRs\)](#), catalytic converters (oxidative, selective, and non-selective), or other emission reduction equipment. A control device may also include any other air pollution control equipment or emission reduction technologies approved by the department to comply with emission standards in this Part.

M. “Department” means the New Mexico environment department.

N. “Downtime” means the period of time when equipment is not in operation, or when a well is producing, and the control device is not in operation.

O. “Enclosed combustion device” means a combustion device where gaseous fuel is combusted in an enclosed chamber. This may include, but is not limited to an enclosed flare, reboiler, and heater.

P. “Existing” means constructed or reconstructed before the effective date of this Part and has not since been modified or reconstructed.

Q. “Gathering and boosting station” ~~means a facility, including all equipment and compressors, located downstream of well sites, designed to compress natural gas from well pressure to gathering system pressure prior to the inlet of a natural gas processing plant.~~ ~~means a permanent combination of equipment that collects or moves natural gas, crude oil, condensate, or produced water between a wellhead site and a midstream oil and natural gas collection or distribution facility, such as a storage vessel battery or compressor station, or into or out of storage.~~

R. “Glycol dehydrator” means a device in which a liquid glycol absorbent, including ethylene glycol, diethylene glycol, or triethylene glycol, directly contacts a natural gas stream and absorbs water.

S. “Hydrocarbon liquid” means any naturally occurring, unrefined petroleum liquid and can include oil, condensate, and intermediate hydrocarbons.

T. “Liquid unloading” means the removal of accumulated liquid from the wellbore that reduces or stops natural gas production.

U. “Liquid transfer” means the loading and unloading of a hydrocarbon liquid or produced water between a storage vessel and tanker truck or tanker rail car for transport.

V. “Local distribution company custody transfer station” means a metering station where the local distribution (LDC) company receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

W. “Natural gas compressor station” means ~~one or more compressors~~ [a facility, including all equipment and compressors](#), designed to compress natural gas from well pressure to gathering system pressure before the inlet of a natural gas processing plant, or to move compressed natural gas through a transmission pipeline. [Natural gas compressor stations include transmission compressor stations.](#)

X. “Natural gas-fired heater” means an enclosed device using a controlled flame and with a primary purpose to transfer heat directly to a process material or to a heat transfer material for use in a process.

Y. “Natural gas processing plant” means the processing equipment engaged in the extraction of natural gas liquid from natural gas or fractionation of mixed natural gas liquid to a natural gas product, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Z. “New” means constructed or reconstructed on or after the effective date of this Part.

AA. “Operator” means the person or persons responsible for the overall operation of a stationary source.

1 **BB. “Optical gas imaging (OGI)”** means an imaging technology that utilizes a high-sensitivity
2 infrared camera designed for and capable of detecting hydrocarbons.

3 **CC. “Owner”** means the person or persons who own a stationary source or part of a stationary source.

4 **DD. “Permanent pit”** means a pit used for collection, retention, or storage of produced water or brine
5 and is installed for longer than one year.

6 **EE. “Pneumatic controller”** means an instrument that is actuated using pressurized gas and used to
7 control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow,
8 and temperature.

9 **FF. “Pneumatic diaphragm pump”** means a positive displacement pump powered by pressurized
10 natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a
11 fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump.
12 A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not
13 considered a diaphragm pump.

14 **GG. “Potential to emit (PTE)”** means the maximum capacity of a stationary source to emit an air
15 contaminant under its physical and operational design. The physical or operational limitation on the capacity of a
16 source to emit an air pollutant, including air pollution control equipment and a restriction on the hours of operation
17 or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the
18 limitation is federally enforceable. The PTE for nitrogen dioxide shall be based on total oxides of nitrogen.

19 **HH. “Produced water”** means a fluid that is an incidental byproduct from drilling for or the
20 production of oil and gas.

21 **II. “Produced water management unit”** means a recycling facility or a permanent pit that is a
22 natural topographical depression, man-made excavation, or diked area formed primarily of earthen materials
23 (although it may be lined with man-made materials), which is designed to accumulate produced water and has a
24 design storage capacity equal to or greater than 50,000 barrels.

25 **JJ. “Qualified Professional Engineer”** means an individual who is licensed by a state as a
26 professional engineer to practice one or more disciplines of engineering and who is qualified by education, technical
27 knowledge, and experience to make the specific technical certifications required under this Part.

28 **KK. “Reciprocating compressor”** means a piece of equipment that increases the pressure of process
29 gas by positive displacement, employing linear movement of a piston rod.

30 **LL. “Reconstruction”** means a modification that results in the replacement of the components or
31 addition of integrally related equipment to an existing source, to such an extent that the fixed capital cost of the new
32 components or equipment exceeds fifty percent of the fixed capital cost that would be required to construct a
33 comparable entirely new facility.

34 **MM. “Recycling facility”** means a stationary or portable facility used exclusively for the treatment, re-
35 use, or recycling of produced water and does not include oilfield equipment such as separators, heater treaters, and
36 scrubbers in which produced water may be used.

37 **NN. “Responsible official”** means one of the following:

38 (1) for a corporation: president, secretary, treasurer, or vice-president of the corporation in
39 charge of a principal business function, or any other person who performs similar policy or decision-making
40 functions for the corporation, or a duly authorized representative of the corporation if the representative is
41 responsible for the overall operation of the source.

42 (2) for a partnership or sole proprietorship: a general partner or the proprietor, respectively.

43 **OO. “Small business facility”** means, for the purposes of this Part, a source that is independently
44 owned or operated by a company that is a not a subsidiary or a division of another business, that employs no more
45 than 10 employees at any time during the calendar year, and that has a gross annual revenue of less than \$250,000.
46 Employees include part-time, temporary, or limited service workers.

47 **PP. “Startup”** means the setting into operation of air pollution control equipment or process
48 equipment.

49 **QQ. “Stationary Source” or “source”** means any building, structure, equipment, facility, installation
50 (including temporary installations), operation, process, or portable stationary source that emits or may emit any air
51 contaminant. Portable stationary source means a source that can be relocated to another operating site with limited
52 dismantling and reassembly.

53 **RR. “Storage vessel”** means a single tank or other vessel that is designed to contain an accumulation
54 of hydrocarbon liquid or produced water and is constructed primarily of non-earthen material including wood,
55 concrete, steel, fiberglass, or plastic, which provide structural support, or a process vessel such as a surge control
56 vessel, bottom receiver, or knockout vessel. A well completion vessel that receives recovered liquid from a well

after commencement of operation for a period that exceeds 60 days is considered a storage vessel. A storage vessel does not include a vessel that is skid-mounted or permanently attached to a mobile source and located at the site for less than 180 consecutive days, such as a truck railcar, or a pressure vessel designed to operate in excess of 204.9 kilopascals without emissions to the atmosphere.

SS. **“Transmission Compressor Station”** means a facility, including all equipment and compressors, that moves natural gas at elevated pressure from well sites or natural gas processing facilities in transmission pipelines to natural gas distribution pipelines or into storage. Transmission compressor stations may include equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.

SS.TT. **“Well workover”** means the repair or stimulation of an existing production well for the purpose of restoring, prolonging, or enhancing the production of hydrocarbons.

UU.TT. **“Wellhead site”** means the equipment directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. A wellhead site may include equipment used for extraction, collection, routing, storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and product piping.

[20.2.50.7 NMAC - N, XX/XX/2021]

20.2.50.8 SEVERABILITY: If any provision of this Part, or the application of this provision to any person or circumstance is held invalid, the remainder of this Part, or the application of this provision to any person or circumstance other than those as to which it is held invalid, shall not be affected thereby.

[20.2.50.8 NMAC - N, XX/XX/2021]

20.2.50.9 CONSTRUCTION: This Part shall be liberally construed to carry out its purpose.

[20.2.50.9 NMAC - N, XX/XX/2021]

20.2.50.10 SAVINGS CLAUSE: Repeal or supersession of prior versions of this Part shall not affect administrative or judicial action initiated under those prior versions.

[20.2.50.10 NMAC - N, XX/XX/2021]

20.2.50.11 COMPLIANCE WITH OTHER REGULATIONS: Compliance with this Part does not relieve a person from the responsibility to comply with other applicable federal, state, or local laws, rules or regulations, including more stringent controls.

[20.2.50.11 NMAC - N, XX/XX/2021]

20.2.50.12 DOCUMENTS: Documents incorporated and cited in this Part may be viewed at the New Mexico environment department, air quality bureau.

[20.2.50.12 NMAC - N, XX/XX/2021]

[The Air Quality Bureau is located at 525 Camino de los Marquez, Suite 1, Santa Fe, New Mexico 87505.]

20.2.23.13-20.2.23.110 [RESERVED]

20.2.50.111 APPLICABILITY:

A. This Part applies to crude oil and natural gas production and processing equipment and operations that extract, collect, separate, dehydrate, store, process, transport, transmit, or handle hydrocarbon liquid or produced water in the areas specified in 20.2.50.2 NMAC and are located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission-natural gas compressor stations, up to the point of the local distribution company custody transfer station.

B. In determining if any source is subject to this Part, including a small business facility as defined in this Part, the owner or operator shall calculate the Potential to Emit (PTE) of such source and shall have the PTE calculation certified by a qualified professional engineer. The requirements of this part may not be considered in the PTE calculation required in this Section or in determining if any source is subject to this part. The calculation shall be kept on file for a minimum of five years and shall be provided to the department upon request.

C. An owner or operator of a small business facility as defined in this Part shall comply with the requirements of this Part as specified in 20.2.50.125 NMAC.

D. Oil refinery and transmission pipelines are not subject to this Part.

[20.2.50.111 NMAC - N, XX/XX/2021]

20.2.50.112 GENERAL PROVISIONS:**A. General requirements:**

(1) Sources subject to emissions standards and requirements under this Part shall be operated and maintained consistent with manufacturer specifications, and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available upon request by the department. For sources constructed prior to 1980 for which no manufacturer specifications and maintenance practices are available, the owner or operator shall develop and follow a maintenance schedule sufficient to operate and maintain such units in good working order. The owner or operator shall keep such maintenance schedules on file and make them available to the department upon request.

(2) Sources subject to emission standards or requirements under this Part shall be operated to minimize emissions of air contaminants, including VOC and NO_x.

(3) Within two years of the effective date of this Part, owners and operators of a source requiring an Equipment Monitoring Tag (EMT) shall physically tag each unit with an EMT, the format of which shall be either RFID, QR, or bar code such that, when scanned it provides a unique identifier of the source. This unique identifier shall act as an index to the source's record of the data required by this Part. The EMT shall be maintained by the owner or operator, and data in the EMT shall provide at a minimum, the following information:

(a) unique unit identification number;

(b) location of the source;

(c) type of source (e.g., tank, VRU, dehydrator, pneumatic controller, etc.);

(d) for each source, the VOC (and NO_x, if applicable) PTE in lbs./hr. and tpy;

(e) for a control device, the controlled VOC and NO_x PTE in lbs./hr. and tpy;

(f) make, model, and serial number; and

(g) a link to the manufacturer's maintenance schedule or repair recommendations.

(4) The EMT shall be installed and maintained by the owner or operator of the facility.

(5) The EMT shall be of a format scannable by an owner or operator's authorized representatives and, upon scanning, shall provide unique identifier that shall index the source's record of the data required by this Part.

(6) The owner or operator shall manage the source's record of data in a database that is able to generate a Compliance Database Report (CDR). The CDR is an electronic report generated by the owner or operator's database and submitted to the department upon request. The format of the CDR shall be determined by the department.

(7) The CDR is a report distinct from the owner or operator's database. The department does not require access to the owner or operator's database, only the CDR.

(8) If read by the owner or operator's authorized representative, the EMT shall access the owner or operator's database record for that source.

(9) The owner or operator shall contemporaneously track each compliance event for each source subject to the EMT requirements of this Part, and shall comply with the following:

(a) data gathered during each monitoring or testing event shall be contemporaneously uploaded into the database as soon as practicable, but no later than three business days of each compliance event.

(b) data required by this Part shall be maintained in the database for at least five years.

(10) The department may request that an owner or operator retain a third party at their own expense to verify any data or information collected, reported, or recorded pursuant to this Part, and make recommendations to correct or improve the collection of data or information. The owner or operator shall submit a report of the verification and any recommendations made by the third party to the department by a date specified and implement the recommendations in the manner approved by the department.

B. Monitoring requirements:

(1) Sources subject to emission standards and monitoring (e.g. inspection, testing, parametric monitoring) requirements under this Part shall be inspected monthly to ensure proper maintenance and operation, unless a different schedule is specified in the Section applicable to that source type. If the equipment is shut down at the time of required periodic testing, monitoring, or inspection, the owner or operator shall not be required to restart the unit for the sole purpose of performing the testing, monitoring, or inspection, but shall note the shut down in the records kept for that equipment for that monitoring event.

(2) An owner or operator may submit for the department's review and approval an equally

effective, enforceable, and equivalent alternative monitoring strategy. Such requests shall be made on an application form provided by the department. The department shall issue a letter approving or denying the requested alternative monitoring strategy. An owner or operator shall comply with the default monitoring requirements required under the applicable Section and shall not operate under an alternative monitoring strategy until it has been approved by the department.

(3) Each monitoring event (e.g. testing, inspection, parametric monitoring) shall be initiated by an initial scanning of the EMT, the results of which shall then be directly uploaded into the database or temporarily into the handheld or other device. Upon completion of the monitoring event, a final scanning of the EMT shall terminate the monitoring event. At a minimum, the uploaded data shall include:

- (a) date and time of the testing, monitoring, or inspection event;
- (b) name of the personnel conducting the testing, monitoring, or inspection;
- (c) identification number and type of unit;
- (d) a description of any maintenance or repair activity conducted; and
- (e) results of testing, monitoring, or inspection as required under this Part.

C. Recordkeeping requirements:

(1) Within three business days of a monitoring event, an electronic record shall be made of the monitoring event and shall include the following data:

- (a) date and time of the testing, monitoring, or inspection event;
- (b) name of the personnel conducting the testing, monitoring, or inspection;
- (c) identification number and type of unit;
- (d) a description of any maintenance or repair activity conducted; and
- (e) results of any testing, monitoring, or inspections required under this Part.

(2) The owner or operator shall keep an electronic record required by this Part for five years. The department may treat loss of data or failure to maintain a record, including failure to transfer a record upon sale or transfer of ownership or operating authority, as a failure to collect the data.

(3) Before the transfer of ownership of equipment subject to this Part, the current owner or operator shall conduct and document a full compliance evaluation of such equipment. The documentation shall include a certification by a responsible official as to whether the equipment is in compliance with the requirements of this Part. The compliance determination shall be conducted no earlier than three months before the transfer of ownership. The owner or operator shall keep the full compliance evaluation and certification by the responsible official for five years.

D. Reporting requirements: Within 24 hours of a request by the department, the owner or operator shall for each unit subject to the request, provide the requested information either by electronically submitting a CDR to the department's Secure Extranet Portal (SEP), or by other means and formats specified by the department in its request.

[20.2.50.112 NMAC - N, XX/XX/2021]

20.2.50.113 ENGINES AND TURBINES:

A. Applicability: Portable and stationary natural gas-fired spark ignition engines, compression ignition engines, and natural gas-fired combustion turbines located at wellhead sites, tank batteries, gathering and boosting ~~sites~~ stations, natural gas processing plants, and ~~transmission-natural gas~~ compressor stations, with a rated horsepower greater than the horsepower ratings of Table 1, 2, and 3 of 20.2.50.113 NMAC are subject to the requirements of 20.2.50.113 NMAC.

B. Emission standards:

(1) The owner or operator of a portable or stationary natural gas-fired spark-ignition engine, compression ignition engine, or natural gas-fired combustion turbine shall ensure compliance with the emission standards by the dates specified in Subsection B of 20.2.50.113 NMAC.

(2) The owner or operator of an existing natural gas-fired spark-ignition engine shall complete an inventory of all existing engines by January 1, 2023, and shall prepare a schedule to ensure that each existing engine does not exceed the emission standards in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC as follows:

- (a) by January 1, 2025, the owner or operator shall ensure at least thirty percent of the company's existing engines meet the emission standards.
- (b) by January 1, 2027, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing engines meets the emission standards.
- (c) by January 1, 2029, the owner or operator shall ensure that the remaining thirty-

five percent of the company's existing engines meets the emission standards.

(d) in lieu of meeting the emission standards for an existing natural gas-fired spark ignition engine, an owner or operator may reduce the annual hours of operation of an engine such that the annual NO_x and VOC emissions are reduced by at least ninety-five percent per year.

Table 1 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES
CONSTRUCTED, RECONSTRUCTED, OR INSTALLED BEFORE THE EFFECTIVE DATE OF 20.2.50
NMAC.

Engine Type	Rated bhp	NO _x	CO	NMNEHC (as propane)
Lean-burn	>1,000	0.50 g/bhp-hr	47 ppmvd @ 15% O ₂ or 93% reduction	0.70 g/bhp-hr
Rich-burn	>1,000	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

(3) The owner or operator of a new natural gas-fired spark ignition engine shall ensure the engine does not exceed the emission standards in table 2 of Paragraph (3) of Subsection B of 20.2.50.113 NMAC upon startup.

Table 2 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES
CONSTRUCTED, RECONSTRUCTED, OR INSTALLED AFTER THE EFFECTIVE DATE OF 20.2.50 NMAC.

Engine Type	Rated bhp	NO _x	CO	NMNEHC (as propane)
Lean-burn	>500 - <1,000	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Lean-burn	≥1,000	0.30 g/bhp-hr uncontrolled or 0.05 g/bhp-hr with control	0.60 g/bhp-hr	0.70 g/bhp-hr
Rich-burn	>500	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

(4) The owner or operator of a natural gas-fired spark ignition engine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(5) The owner or operator of a compression ignition engine shall ensure compliance with the following emission standards:

(a) a new portable or stationary compression ignition engine with a maximum design power output equal to or greater than 500 horsepower that is not subject to the emission standards under Subparagraph (b) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC shall limit NO_x emissions to not more than nine g/bhp-hr upon startup.

(b) a stationary compression ignition engine that is subject to and complying with Subpart III of 40 CFR Part 60, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, is not subject to the requirements of Subparagraph (a) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC.

(6) The owner or operator of a portable or stationary compression ignition engine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(7) The owner or operator of a stationary natural gas-fired combustion turbine with a maximum design rating equal to or greater than 1,000 bhp shall comply with the applicable emission standards for an existing, new, or reconstructed turbine listed in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC.

Table 3 - EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES

For each natural gas-fired combustion turbine constructed or reconstructed and installed before the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards no later than two years from the effective date of this Part:			
Turbine Rating (bhp)	NO _x (ppmvd @15% O ₂)	CO (ppmvd @ 15% O ₂)	NMNEHC (as propane, ppmvd @15% O ₂)

≥1,000 and <5,000	50	50	9
≥5,000 and <15,000	50	50	9
≥15,000	50	50 or 93% reduction	5 or 50% reduction
For each natural gas-fired combustion turbine constructed or reconstructed and installed on or after the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards upon startup:			
Turbine Rating (bhp)	NO _x (ppmvd @15% O ₂)	CO (ppmvd @ 15% O ₂)	NMNEHC (as propane, ppmvd @15% O ₂)
≥1,000 and <5,000	25	25	9
≥5,000 and <15,900	15	10	9
≥15,900	9.0 Uncontrolled or 2.0 with Control	10 Uncontrolled or 1.8 with Control	5

(8) The owner or operator of a stationary natural gas-fired combustion turbine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(9) The owner or operator of an engine or turbine shall install an EMT on the engine or turbine in accordance with 20.2.50.112 NMAC.

(10) The owner or operator of an emergency use engine that is operated less than 100 hours per year is not subject to the emissions standards in this Part but shall be equipped with a non-resettable hour meter to monitor and record any hours of operation.

C. Monitoring requirements:

(1) Maintenance and repair for a spark-ignition engine, compression-ignition engine, and stationary combustion turbine shall meet the minimum manufacturer recommended maintenance schedule. The following maintenance, adjustment, replacement, or repair events for engines and turbines shall be documented as they occur:

(a) routine maintenance that takes a unit out of service for more than two hours during any 24-hour period; and

(b) unscheduled repairs that require a unit to be taken out of service for more than two hours during any 24-hour period.

(2) Catalytic converters (oxidative, selective and non-selective) and AFR controllers shall be maintained according to manufacturer or supplier recommended maintenance schedules, including replacement of oxygen sensors as necessary for oxygen-based controllers. During periods of catalytic converter or AFR controller maintenance, the owner or operator shall shut down the engine or turbine until the catalytic converter or AFR controller can be replaced with a functionally equivalent spare to allow the engine or turbine to return to operation.

(3) For equipment operated for 500 hours per year or more, compliance with the emission standards in Subsection B of 20.2.50.113 NMAC shall be demonstrated by performing an initial emissions test, followed by annual tests, for NO_x, CO, and non-methane non-ethane hydrocarbons (NMNEHC) using a portable analyzer or U.S. EPA reference method. For units with g/hp-hr emission standards, the engine load shall be calculated using the following equations:

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (scf/hr)} \times \text{Measured fuel heating value (LHV btu/scf)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (gal/hr)} \times \text{Measured fuel heating value (LHV btu/gal)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

Where: LVH = lower heating value, btu/scf, or btu/gal, as appropriate; and
BSFC = brake specific fuel consumption

(a) emissions testing events shall be conducted at ninety percent or greater of the

unit's capacity. If the ninety percent capacity cannot be achieved, the monitoring and testing shall be conducted at the maximum achievable capacity or load under prevailing operating conditions. The load and the parameters used to calculate it shall be recorded to document operating conditions at the time of testing and shall be included with the test report.

(b) emissions testing utilizing a portable analyzer shall be conducted in accordance with the requirements of the current version of ASTM D 6522. If a portable analyzer has met a previously approved department criterion, the analyzer may be operated in accordance with that criterion until it is replaced.

(c) the default time period for a test run shall be at least 20 minutes.

(d) an emissions test shall consist of three separate runs, with the arithmetic mean of the results from the three runs used to determine compliance with the applicable emission standard.

(e) during emissions tests, pollutant and diluent concentration shall be monitored and recorded. Fuel flow rate shall be monitored and recorded if stack gas flow rate is determined utilizing U.S. EPA reference method 19. This information shall be included with the periodic test report.

(f) stack gas flow rate shall be calculated in accordance with U.S. EPA reference method 19 utilizing fuel flow rate (scf) determined by a dedicated fuel flow meter and fuel heating value (Btu/scf). The owner or operator shall provide a contemporaneous fuel gas analysis (preferably on the day of the test, but no earlier than three months before the test date) and a recent fuel flow meter calibration certificate (within the most recent quarter) with the final test report. Alternatively, stack gas flow rate may be determined by using U.S. EPA reference methods 1 through 4 or through the use of manufacturer provided fuel consumption rates.

(g) upon request by the department, an owner or operator shall submit a notification and protocol for an initial or annual emissions test.

(h) emissions testing shall be conducted at least once per calendar year. Emission testing required by Subparts GG, IIII, JJJJ, or KKKK of 40 CFR 60, or Subpart ZZZZ of 40 CFR 63, may be used to satisfy the emissions testing requirements if it meets the requirements of 20.2.50.113 NMAC and is completed at least once per calendar year.

(4) The owner or operator of equipment operated less than 500 hours per year shall monitor the hours of operation using a non-resettable hour meter and shall test the unit at least once per 8760 hours of operation in accordance with the emissions testing requirements in Paragraph (3) of Subsection C of 20.2.50.113 NMAC.

(5) An owner or operator of an emergency use engine operated for less than 100 hours per year shall monitor the hours of operation by a non-resettable hour meter.

(6) An owner or operator limiting the annual operating hours of an engine to meet the requirements of Paragraph (2) of Subsection B of 20.2.50.113 NMAC shall monitor the hours of operation by a non-resettable hour meter.

(7) Prior to monitoring, testing, inspection, or maintenance of an engine or turbine, the owner or operator shall scan the EMT, and the monitoring data entry shall be made in accordance with the requirements of 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain a record in accordance with 20.2.50.112 NMAC for the engine or turbine. The record shall include:

(a) the make, model, serial number, and EMT for the engine or turbine;

(b) a copy of the engine, turbine, or control device manufacturer recommended maintenance and repair schedule;

(c) all inspection, maintenance, or repair activity on the engine, turbine, and control device, including:

(i) the date and time of an inspection, maintenance or repair;

(ii) the date a subsequent analysis was performed (if applicable);

(iii) the name of the personnel conducting the inspection, maintenance or repair;

(iv) a description of the physical condition of the equipment as found during the inspection;

(v) a description of maintenance or repair activity conducted; and

(vi) the results of the inspection and any required corrective actions.

(2) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain records of initial and annual emissions testing for the engine or turbine.

1 The records shall include:

- 2 (a) the make, model, serial number, and EMT for the tested engine or turbine;
- 3 (b) the date and time of sampling or measurements;
- 4 (c) the date analyses were performed;
- 5 (d) the name of the personnel and the qualified entity that performed the analyses;
- 6 (e) the analytical or test methods used;
- 7 (f) the results of analyses or tests;
- 8 (g) for equipment operated less than 500 hours per year, the total annual hours of
- 9 operation as recorded by the non-resettable hour meter; and
- 10 (h) operating conditions at the time of sampling or measurement.

11 (3) The owner or operator of an emergency use engine operated less than 100 hours per year

12 shall record the total annual hours of operation as recorded by the non-resettable hour meter.

13 (4) The owner or operator limiting the annual operating hours of an engine to meet the

14 requirements of Paragraph (2) of Subsection B of 20.2.50.113 NMAC shall record the hours of operation by a non-

15 resettable hour meter. The owner or operator shall calculate and record the annual NOx and VOC emission

16 calculation, based on the engine's actual hours of operation, to demonstrate the ninety-five percent emission

17 reduction requirement is met.

18 **E. Reporting requirements:** The owner or operator shall comply with the reporting requirements in

19 20.2.50.112 NMAC.

20 [20.2.50.113 NM-C - N, XX/XX/2021]

21

22 **20.2.50.114 COMPRESSOR SEALS:**

23 **A. Applicability:**

24 (1) Centrifugal compressors using wet seals and located at tank batteries, gathering and

25 boosting ~~sites~~stations, natural gas processing plants, or ~~transmission-natural gas~~ compressor stations are subject to

26 the requirements of 20.2.50.114 NMAC. Centrifugal compressors located at wellhead sites are not subject to the

27 requirements of 20.2.50.114 NMAC.

28 (2) Reciprocating compressors located at tank batteries, gathering and boosting ~~sites~~stations,

29 natural gas processing plants, or ~~transmission-natural gas~~ compressor stations are subject to the requirements of

30 20.2.50.114 NMAC. Reciprocating compressors located at wellhead sites are not subject to the requirements of

31 20.2.50.114 NMAC.

32 **B. Emission standards:**

33 (1) The owner or operator of an existing centrifugal compressor shall control VOC emissions

34 from a centrifugal compressor wet seal fluid degassing system by at least ninety-five percent within two years of the

35 effective date of this Part. Emissions shall be captured and routed via a closed vent system to a control device,

36 recovery system, fuel cell, or a process stream.

37 (2) The owner or operator of an existing reciprocating compressor shall, either:

38 (a) replace the reciprocating compressor rod packing after every 26,000 hours of

39 compressor operation or every 36 months, whichever is reached later. The owner or operator shall begin counting

40 the hours of compressor operation toward the first replacement of the rod packing upon the effective date of this

41 Part; or

42 (b) beginning no later than two years from the effective date of this Part, collect

43 emissions from the rod packing under negative pressure and route them via a closed vent system to a control device,

44 recovery system, fuel cell, or a process stream.

45 (3) The owner or operator of a new centrifugal compressor shall control VOC emissions

46 from the centrifugal compressor wet seal fluid degassing system by at least ninety-eight percent upon startup.

47 Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or

48 process stream.

49 (4) The owner or operator of a new reciprocating compressor shall, upon startup, either:

50 (a) replace the reciprocating compressor rod packing after every 26,000 hours of

51 compressor operation, or every 36 months, whichever is reached later; or

52 (b) collect emissions from the rod packing under negative pressure and route them

53 via a closed vent system to a control device, a recovery system, fuel cell or a process stream.

54 (5) The owner or operator of a centrifugal or reciprocating compressor shall install an EMT

55 on the compressor in accordance with 20.2.50.112 NMAC.

56 (6) The owner or operator complying with the emission standards in Subsection B of

20.2.50.114 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator of a centrifugal compressor complying with Paragraph (1) or (3) of Subsection B of 20.2.50.114 NMAC shall maintain a closed vent system encompassing the wet seal fluid degassing system that complies with the monitoring requirements in 20.2.50.115 NMAC.

(2) The owner or operator of a reciprocating compressor complying with Subparagraph (a) of Paragraph (2) or Subparagraph (a) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall continuously monitor the hours of operation with a non-resettable hour meter and track the number of hours since initial startup or since the previous reciprocating compressor rod packing replacement.

(3) The owner or operator of a reciprocating compressor complying with Subparagraph (b) of Paragraph (2) or Subparagraph (b) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall monitor the rod packing emissions collection system semiannually to ensure that it operates under negative pressure and routes emissions through a closed vent system to a control device, recovery system, fuel cell, or process stream.

(4) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a closed vent system or control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(5) The owner or operator of a centrifugal or reciprocating compressor shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a centrifugal compressor using a wet seal fluid degassing system shall maintain a record of the following:

(a) the location of the centrifugal compressor;

(b) the date of construction, reconstruction, or modification of the centrifugal compressor;

(c) the monitoring required in Subsection C of 20.2.50.114 NMAC, including the time and date of the monitoring, the personnel conducting the monitoring, a description of any problem observed during the monitoring, and a description of any corrective action taken; and

(d) the type, make, model, and identification number of a control device used to comply with the control requirements in Subsection B of 20.2.50.114 NMAC.

(2) The owner or operator of a reciprocating compressor shall maintain a record of the following:

(a) the location of the reciprocating compressor;

(b) the date of construction, reconstruction, or modification of the reciprocating compressor; and

(c) the monitoring required in Subsection C of 20.2.50.114 NMAC, including:

(i) the number of hours of operation since initial startup or the last rod packing replacement;

(ii) the records of pressure in the rod packing emissions collection system; and

(iii) the time and date of the inspection, the personnel conducting the inspection, a notation of which checks required in Subsection C of 20.2.50.114 NMAC were completed, a description of problems observed during the inspection, and a description and date of corrective actions taken.

(3) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a control device or closed vent system shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(4) The owner or operator of a centrifugal or reciprocating compressor shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator of a centrifugal or reciprocating compressor shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.114 NM-C - N, XX/XX/2021]

20.2.50.115 CONTROL DEVICES:

A. Applicability: These requirements apply to control devices as defined in 20.2.50.7 NMAC and used to comply with the emission standards and emission reduction requirements in this Part.

B. General requirements:

(1) Control devices used to demonstrate compliance with this Part shall be installed, operated, and maintained consistent with manufacturer specifications, and good engineering and maintenance practices.

(2) Control devices shall be adequately designed and sized to achieve the control efficiency rates required by this Part and to handle fluctuations in emissions of VOC or NO_x.

(3) The owner or operator of a control device used to comply with the emission standards in this Part shall install an EMT on the control device in accordance with 20.2.50.112 NMAC.

(4) The owner or operator shall inspect control devices used to comply with this Part at least monthly to ensure proper maintenance and operation. Prior to an inspection or monitoring event, the owner or operator shall scan the EMT and the required monitoring data shall be electronically captured in accordance with this Part.

(5) The owner or operator shall ensure that a control device used to comply with emission standards in this Part operates as a closed vent system that captures and routes VOC emissions to the control device, and that unburnt gas is not directly vented to the atmosphere.

(6) The owner or operator of a closed vent system for a centrifugal compressor wet seal fluid degassing system, reciprocating compressor, pneumatic controller or pump, or storage vessel using a control device or routing emissions to a process shall:

(a) ensure the control device or process is of sufficient design and capacity to accommodate all emissions from the affected sources;

(b) conduct an assessment to confirm that the closed vent system is of sufficient design and capacity to ensure that all emissions from the affected equipment are routed to the control device or process; and

(c) have the closed vent system certified by a qualified professional engineer or an in-house engineer with expertise regarding the design and operation of the closed vent system in accordance with Paragraphs (c)(i) and (ii) of this Section.

(i) The assessment of the closed vent system shall be prepared under the direction or supervision of a qualified professional engineer or an in-house engineer who signs the certification in Paragraph (c)(ii) of this Section.

(ii) the owner or operator shall provide the following certification, signed and dated by a qualified professional engineer or an in-house engineer: "I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted, and this report was prepared pursuant to the requirements of this Part. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(7) The owner or operator shall keep manufacturer specifications for all control devices on file. The information shall include:

(a) manufacturer name, make, and model;

(b) maximum heating value for an open flare, ECD, or TO;

(c) maximum rated capacity for an open flare, ECD/TO, or VRU;

(d) gas flow range for an open flare, ECD, or TO; and

(e) designed destruction or vapor recovery efficiency.

C. Requirements for open flares:

(1) Emission standards:

(a) the flare shall combust the gas sent to the flare and combustion shall be maintained for the duration of time that gas is sent to the flare. The owner or operator shall not send gas to the flare in excess of the manufacturer maximum rated capacity.

(b) the owner or operator shall equip each new and existing flare (except those flares required to meet the requirements of Paragraph (C) of this Subsection) with a continuous pilot flame, an operational auto-igniter, or require manual ignition, and shall comply with the following:

(i) a flare with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure the flare is operated with a flame present at all times when gas is being sent to the flare.

(ii) the owner or operator of a flare with manual ignition shall inspect and ensure a flame is present upon initiating a flaring event.

(iii) a new flare controlling a continuous gas stream shall be equipped with a continuous pilot flame upon startup.

(iv) an existing flare controlling a continuous gas stream constructed before the effective date of this Part shall be equipped with a continuous pilot no later than one year after the effective date of this Part.

(c) an existing flare located at a site with an annual average daily production of equal to or less than 10 barrels of oil per day or an average daily production of 60,000 standard cubic feet of natural gas shall be equipped with an auto-ignitor, continuous pilot, or technology (e.g. alarm) that alerts the owner or operator of a flare malfunction, if replaced or reconstructed after the effective date of this Part.

(d) the owner or operator shall operate a flare with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The flare shall be designed so that an observer can, by means of visual observation from the outside of the flare or by other means such as a continuous monitoring device, determine whether it is operating properly.

(e) the owner or operator shall repair the flare within three business days of any alarm activation.

(2) Monitoring requirements:

(a) the owner or operator of a flare with a continuous pilot or auto igniter shall continuously monitor the presence of a pilot flame, or presence of flame during flaring if using an auto igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department;

(b) the owner or operator of a manually ignited flare shall monitor the presence of a flame using continuous visual observation during a flaring event;

(c) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the flare pilot or auto igniter flame is present to certify compliance with visible emission requirements. The observation period shall be a minimum of 15 consecutive minutes;

(d) prior to an inspection or monitoring event, the EMT on the flare shall be scanned and the required monitoring data shall be electronically captured during the event in accordance with the monitoring requirements of 20.2.50.112 NMAC; and

(e) the owner or operator shall monitor the technology that alerts the owner or operator of a flare malfunction and any instances of technology or alarm activation.

(3) Recordkeeping requirements: The owner or operator of an open flare shall keep a record of the following:

(a) any instance of alarm activation, including the date and cause of alarm activation, action taken to bring the flare into a normal operating condition, the name of the personnel conducting the inspection, and any maintenance activity performed;

(b) the results of the U.S. EPA method 22 observations;

(c) the monitoring of the presence of a flame on a manual flare during a flaring event as required under Subparagraph (b) of Paragraph (2) of Subsection C of 20.2.50.115 NMAC;

(d) the results of the gas analysis for the gas being flared, including VOC content and heating value; and

(e) any instance of technology or alarm activation of a malfunctioning flare, including the date and cause of the activation, the action taken to bring the flare into normal operating condition, date of repair, name of the personnel conducting the inspection, and any maintenance activities performed.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

D. Requirements for enclosed combustion devices (ECD) and thermal oxidizers (TO):

(1) Emission standards:

(a) the ECD/TO shall combust the gas sent to the ECD/TO. The owner or operator shall not send gas to the ECD/TO in excess of the manufacturer maximum rated capacity.

(b) the owner or operator shall equip an ECD/TO with a continuous pilot flame or an auto-igniter. Existing ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter no later than one year after the effective date. New ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter upon startup.

(c) ECD/TO with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure that the ECD/TO is operated with a flame present at all times when gas is sent to the ECD/TO. Combustion shall be maintained for the duration of time that gas is sent to the ECD/TO.

(d) the owner or operator shall operate an ECD/TO with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The ECD/TO shall be designed so that an observer can, by means of visual observation from the outside of the ECD/TO or by other means such as a continuous monitoring device, determine whether it is operating properly.

(2) Monitoring requirements:

(a) the owner or operator of an ECD/TO with a continuous pilot or an auto igniter shall continuously monitor the presence of a pilot flame, or of a flame during combustion if using an auto-igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department.

(b) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the ECD/TO pilot flame or auto igniter flame is present to certify compliance with the visible emission requirements. The period of observation shall be a minimum of 15 consecutive minutes.

(c) prior to an inspection or monitoring event, the EMT on the unit shall be scanned and the required monitoring data shall be electronically captured during the monitoring event in accordance with the monitoring requirements of 20.2.50.112 NMAC.

(3) Recordkeeping requirements: The owner or operator of an ECD/TO shall keep records of the following:

(a) any instance of an alarm activation, including the date and cause of the activation, any action taken to bring the ECD/TO into normal operating condition, the name of the personnel conducting the inspection, and any maintenance activities performed;

(b) the result of the U.S. EPA method 22 observation; and

(c) the results of gas analysis for the gas being combusted, including VOC content and heating value.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

E. Requirements for vapor recover units (VRU):

(1) Emission standards:

(a) the owner or operator shall operate the VRU as a closed vent system that captures and routes all VOC emissions directly back to the process or to a sales pipeline and does not vent to the atmosphere.

(b) the owner or operator shall control VOC emissions during startup, shutdown, maintenance, or other VRU downtime with a backup control device (e.g. flare, ECD, TO) or redundant VRU.

(2) Monitoring Requirements:

(a) the owner or operator shall comply with the standards for equipment leaks in 20.2.50.116 NMAC, or, alternatively, shall implement a program that meets the requirements of Subpart OOOOa of 40 CFR 60.

(b) prior to a VRU inspection or monitoring event, the EMT on the unit shall be scanned and the required monitoring data shall be electronically captured during the monitoring event in accordance with the monitoring requirements of 20.2.50.112 NMAC.

(3) Recordkeeping requirements: For a VRU inspection or monitoring event, the owner or operator shall record the result of the event in accordance with 20.2.50.112 NMAC, including the name of the personnel conducting the inspection, and any maintenance or repair activities required. The owner or operator shall record the type of redundant control device used during VRU downtime.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

F. Recordkeeping requirements: The owner or operator of a control device shall maintain a record of the following:

(1) the certification of the closed vent system as required by this Part; and

(2) the information required in Paragraph (7) of Subsection B of 20.2.50.115 NMAC.

G. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.115 NM-C - N, XX/XX/2021]

20.2.50.116 EQUIPMENT LEAKS AND FUGITIVE EMISSIONS:

A. Applicability: Wellhead sites, tank batteries, gathering and boosting sites, gas processing plants, natural gas transmission-compressor stations, and associated piping and components are subject to the requirements of 20.2.50.116 NMAC. The requirements of this Part may be considered in the facility's PTE and in determining the monitoring frequency requirements of this Section.

B. Emission standards: The owner or operator of oil and gas production and processing equipment located at wellhead sites, tank batteries, gathering and boosting sites, gas processing plants, or transmission natural gas compressor stations shall demonstrate compliance with this Part by performing the monitoring, recordkeeping, and reporting requirements specified in 20.2.50.116 NMAC.

C. Default Monitoring requirements: Owners and operators shall comply with the following monitoring requirements and the monitoring requirements in 20.2.50.112 NMAC:

(1) The owner or operator of a facility with an annual average daily production of greater than 10 barrels of oil per day or an average daily production of greater than 60,000 standard cubic feet per day of natural gas shall, at least weekly, conduct audio, visual, and olfactory (AVO) inspections of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify defects and leaking components as follows:

(a) conduct a visual inspection for: cracks, holes, or gaps in piping or covers; loose connections; liquid leaks; broken or missing caps; broken, cracked or otherwise damaged seals or gaskets; broken or missing hatches; or broken or open access covers or other closure or bypass devices;

(b) conduct an audio inspection for pressure leaks and liquid leaks;

(c) conduct an olfactory inspection for unusual or strong odors;

(d) any positive detection during the AVO inspection shall be considered a leak; and

(e) a leak discovered by an AVO inspection shall be tagged with a visible tag and reported to management or their designee within three calendar days.

(2) The owner or operator of a facility with an annual average daily production of equal to or less than 10 barrels of oil per day or an average daily production of equal to or less than 60,000 standard cubic feet per day of natural gas shall, at least monthly, conduct an audio, visual, and olfactory (AVO) inspection of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify a defect and leaking component as specified in Subparagraphs (a) through (e) of Paragraph (1) of Subsection (C) of 20.2.50.116 NMAC.

(3) The owner or operator of the following facilities shall conduct an inspection using U.S. EPA method 21 or optical gas imaging (OGI) of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify leaking components at a frequency determined according to the following schedules:

(a) for wellhead sites or tank battery facilities:

(i) annually at facilities with a PTE less than two tpy VOC;

(ii) semi-annually at facilities with a PTE equal to or greater than two tpy and less than five tpy VOC; and

(iii) quarterly at facilities with a PTE equal to or greater than five tpy VOC.

(b) for gathering and boosting sites, gas processing plants, and transmission natural gas compressor stations:

(i) quarterly at facilities with a PTE less than 25 tpy VOC; and

(ii) monthly at facilities with a PTE equal to or greater than 25 tpy VOC.

(4) Inspections using U.S. EPA method 21 shall meet the following requirements:

(a) the instrument shall be calibrated before each day of its use by the procedures specified in U.S. EPA method 21;

(b) the instrument shall be calibrated with zero air (less than 10 ppm of hydrocarbon in air), and a mixture of methane or n-hexane and air at a concentration near, but not more than, 10,000 ppm methane or n-hexane; and

(c) a leak is detected if the instrument records a measurement of 500 ppm or greater of hydrocarbon and the measurement is not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

(5) Inspections using OGI shall meet the following requirements:

(a) the instrument shall comply with the specifications, daily instrument checks, and leak survey requirements set forth in Subparagraphs (1) through (3) of Paragraph (i) of 40 CFR 60.18;

(b) a leak is detected if the emission images recorded by the OGI instrument are not associated with normal equipment operation, such as pneumatic device actuation or crank case ventilation.

(6) Components that are difficult, unsafe, or inaccessible to monitor, as determined by the following conditions, are not required to be inspected until it becomes feasible to do so:

(a) difficult to monitor components are those that require elevating the monitoring personnel more than two meters above a supported surface, or that cannot be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to seven and six tenths meters (25 feet) above the ground;

(b) unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring; and

(c) inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

D. Alternative equipment leak monitoring plans: As an equivalent means of compliance with Subsection C of 20.2.50.116 NMAC, an owner or operator may comply with the equipment leak requirements through an alternative monitoring plan as follows:

(1) An owner or operator may comply with an individual alternative monitoring plan, subject to the following requirements:

(a) the proposed alternative monitoring plan shall be submitted to and approved by the department prior to conducting monitoring under that plan.

(b) the department may terminate an approved alternative monitoring plan if the department finds that the owner or operator failed to comply with a provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(c) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under Subsection C of 20.2.50.116 NMAC within 15 days.

(2) An owner or operator may comply with a pre-approved monitoring plan maintained by the department, subject to the following requirements:

(a) the owner or operator shall notify the department of the intent to conduct monitoring under a pre-approved monitoring plan, and identify which pre-approved plan will be used, at least 15 days prior to conducting monitoring under that plan.

(b) the department may terminate the use of a pre-approved monitoring plan by the owner or operator if the department finds that the owner or operator failed to comply with the provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(c) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under of Subsection C of 20.2.50.116.C NMAC within 15 days.

E. Repair requirements: For a leak detected pursuant to monitoring conducted under 20.2.50.116 NMAC:

(1) the owner or operator shall place a visible tag on the leaking component until the component has been repaired;

(2) leaks shall be repaired within 15 days of discovery, except for leaks detected using OGI, which shall be repaired within seven days of discovery;

(3) the equipment must be re-monitored no later than 15 days after discovery of the leak to demonstrate that it has been repaired; and

(4) if the leak cannot be repaired within 15 days of discovery, or within seven days for a leak detected using OGI, without a process unit shutdown, the leak may be designated "Repair delayed," and must be repaired before the end of the next process unit shutdown.

F. Recordkeeping requirements:

(1) The owner or operator shall keep a record of the following for all AVO, RM21, OGI, or alternative equipment leak monitoring inspection conducted as required under 20.2.50.116 NMAC, and shall provide the record to the department upon request:

(a) facility location;

(b) date of inspection;

(c) monitoring method (e.g. AVO, RM 21, OGI, alternative method approved by the department);

(d) name of the personnel performing the inspection;

(e) a description of any leak requiring repair or a note that no leak was found; and

(f) whether a visible flag was placed on the leak or not;

(2) The owner or operator shall keep the following record for any leak that is detected:

- (a) the date the leak is detected;
- (b) the date of attempt to repair;
- (c) for a leak with a designation of “repair delayed” the following shall be recorded:
 - (i) reason for delay if a leak is not repaired within the required number of days after discovery;
 - (ii) signature of the authorized representative who determined that the repair could not be implemented without a process unit shutdown;
- (d) date of successful leak repair;
- (e) date the leak was monitored after repair and the results of the monitoring; and
- (f) a description of the component that is designated as difficult, unsafe, or inaccessible to monitor, an explanation stating why the component was so designated, and the schedule for repairing and monitoring the component.

(3) For a leak detected using OGI, the owner or operator shall keep records of the specifications, the daily instrument check, and the leak survey requirements specified at 40 CFR 60.18(i)(1)-(3).

(4) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

G. Reporting requirements:

(1) The owner or operator shall certify the use of an alternative equipment leak monitoring plan under Subsection D of 20.2.50.116 NMAC to the department annually, if used.

(2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.116 NMAC - N, XX/XX/2021]

20.2.50.117 NATURAL GAS WELL LIQUID UNLOADING:

A. Applicability: Liquid unloading operations including down-hole well maintenance events at natural gas wells are subject to the requirements of 20.2.50.117 NMAC.

B. Emission standards:

(1) The owner or operator of a natural gas well shall use best management practices during the life of the well to avoid the need for liquid unloading.

(2) The owner or operator of a natural gas well shall use the following best management practices during liquid unloading to minimize emissions, consistent with well site conditions and good engineering practices:

- (a) reduce wellhead pressure before blowdown;
- (b) monitor manual liquid unloading in close proximity to the well or via remote telemetry; and
- (c) close well head vents to the atmosphere and return the well to normal production operation as soon as practicable.

(3) The owner or operator of a natural gas well shall use one of the following methods to reduce emissions during an unloading event:

- (a) installation and use of a plunger lift;
- (b) installation and use of an artificial lift engine; or
- (c) installation and use of a control device.

(4) The owner or operator of a natural gas well shall install an EMT on the natural gas well in accordance with 20.2.50.112 NMAC.

C. Monitoring requirements:

(1) The owner or operator shall monitor the following parameters during liquid unloading:

- (a) wellhead pressure;
- (b) flow rate of the vented natural gas (to the extent feasible); and
- (c) duration of venting to the storage vessel or atmosphere.

(2) The owner or operator shall calculate the volume and mass of VOC vented during a liquid unloading event.

(3) A liquid unloading event shall include the scanning of the EMT and monitoring data entry in accordance with the requirements of 20.2.50.112 NMAC.

(4) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

- (1) The owner or operator shall keep the following records for liquid unloading:
- (a) identification number and location of the well;
 - (b) date the liquid unloading was performed;
 - (c) wellhead pressure;
 - (d) flow rate of the vented natural gas (to the extent feasible. If not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation);
 - (e) duration of venting to the storage vessel or atmosphere;
 - (f) a description of the management practice used to minimize release of VOC emissions before and during the liquid unloading;
 - (g) the type of control device used to control VOC emissions during the liquid unloading; and
 - (h) a calculation of the VOC emissions vented during the liquid unloading based on the duration, volume, and mass of VOC.
- (2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.117 NMAC - N, XX/XX/2021]

20.2.50.118 GLYCOL DEHYDRATORS:

A. Applicability: Glycol dehydrators with a PTE equal to or greater than two tpy of VOC and located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission-natural gas compressor stations are subject to the requirements of 20.2.50.118 NMAC.

B. Emission standards:

- (1) Existing glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still vent and flash tank no later than two years after the effective date. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.
- (2) New glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still vent and flash tank upon startup. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.
- (3) The owner or operator of a glycol dehydrator shall comply with the following requirements:
- (a) still vent and flash tank emissions shall be routed at all times to the reboiler firebox, condenser, combustion control device, fuel cell, to a process point that either recycles or recompresses the emissions or uses the emissions as fuel, or to a VRU that reinjects the VOC emissions back into the process stream or natural gas gathering pipeline;
 - (b) if a VRU is used, it shall consist of a closed loop system of seals, ducts and a compressor that reinjects the natural gas into the process or the natural gas pipeline. The VRU shall be operational at least ninety-five percent of the time the facility is in operation, resulting in a minimum combined capture and control efficiency of ninety-five percent. The VRU shall be installed, operated, and maintained according to the manufacturer's specifications;
 - (c) still vent and flash tank emissions shall not be vented to the atmosphere during normal operation; and
 - (d) the owner or operator of a glycol dehydrator shall install an EMT on the glycol dehydrator in accordance with 20.2.50.112 NMAC.
- (4) an owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through use of a control device shall comply with the requirements in 20.2.50.115 NMAC.
- (5) The requirements of Subsection B of 20.2.50.118 NMAC cease to apply when the uncontrolled actual annual VOC emissions from a new or existing glycol dehydrator are less than two tpy VOC.
- C. Monitoring requirements:**
- (1) The owner or operator of a glycol dehydrator shall conduct an annual extended gas analysis on the dehydrator inlet gas and calculate the uncontrolled and controlled VOC emissions in tpy.
- (2) The owner or operator of a glycol dehydrator shall inspect the glycol dehydrator,

including the reboiler and regenerator, and the control device or process the emissions are being routed, semi-annually to ensure it is operating as initially designed and in accordance with the manufacturer recommended operation and maintenance schedule.

(3) An owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through the use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) Owners and operators shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a glycol dehydrator shall maintain a record of the following:

(a) dehydrator location and identification number;

(b) glycol circulation rate, monthly natural gas throughput, and the date of the most recent throughput measurement;

(c) data and methodology used to estimate the PTE of VOC (must be a department approved calculation methodology);

(d) amount of controlled and uncontrolled VOC emissions in tpy;

(e) type, make, model, and identification number of the control device or process the emissions are being routed;

(f) date and results of any equipment inspection, including maintenance or repair activities required to bring the glycol dehydrator into compliance; and

(g) a copy of the glycol dehydrator manufacturer operation and maintenance recommendations.

(2) An owner or operator complying with the requirements in Paragraph (1) or (2) of Subsection B of 20.2.50.118 NMAC through use of a control device as defined in this Part shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(3) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.118 NMAC - N, XX/XX/2021]

20.2.50.119 HEATERS:

A. Applicability: Natural gas-fired heaters with a rated heat input equal to or greater than 10 MMBtu/hour including heater treaters, heated flash separators, evaporator units, fractionation column heaters, and glycol dehydrator reboilers in use at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission-natural gas compressor stations are subject to the requirements of 20.2.50.119 NMAC.

B. Emission standards:

(1) Natural gas-fired heaters shall comply with the emission limits in table 1 of 20.2.50.119 NMAC.

Table 1 - EMISSION STANDARDS FOR NO_x AND CO

Date of Construction:	NO _x (ppmvd @ 3% O ₂)	CO (ppmvd @ 3% O ₂)
Constructed or reconstructed before the effective date of 20.2.50 NMAC	30	300
Constructed or reconstructed on or after the effective date of 20.2.50 NMAC	30	130

(2) Existing natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC no later than one year after the effective date of this Part.

(3) New natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC upon startup.

(4) The owner or operator of a natural gas-fired heater shall install an EMT on the heater in accordance with 20.2.50.112 NMAC.

C. Monitoring requirements:

(1) The owner or operator shall:

(a) conduct emission testing for NO_x and CO within 180 days of the compliance date specified in Paragraph (2) or (3) of Subsection B of 20.2.50.119 NMAC and at least every two years thereafter.

(b) inspect, maintain, and repair the heater in accordance with the manufacturer specifications at least once every two years following the applicable compliance date specified in 20.2.50.119 NMAC. The inspection, maintenance, and repair shall include the following:

(i) inspecting the burner and cleaning or replacing components of the burner as necessary;

(ii) inspecting the flame pattern and adjusting the burner as necessary to optimize the flame pattern consistent with the manufacturer specifications and good engineering practices;

(iii) inspecting the AFR controller and ensuring it is calibrated and functioning properly;

(iv) optimizing total emissions of CO consistent with the NO_x requirement, manufacturer specifications, and good combustion engineering practices; and

(v) measuring the concentrations in the effluent stream of CO in ppmvd and O₂ in volume percent before and after adjustments are made in accordance with Subparagraph (c) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC.

(2) The owner or operator shall comply with the following periodic testing requirements:

(a) conduct three test runs of at least 20-minutes duration within ten percent of one-hundred percent peak, or the highest achievable, load;

(b) determine NO_x and CO emissions and O₂ concentrations in the exhaust with a portable analyzer used and maintained in accordance with the manufacturer specifications and following the procedures specified in the current version of ASTM D6522;

(c) if the measured NO_x or CO emissions concentrations are exceeding the emissions limits of table 1 of 20.2.50.119 NMAC, the owner or operator shall repeat the inspection and tune-up in Subparagraph (b) of Paragraph (1) of Subsection C of 20.2.50.119 NMAC within 30 days of the periodic testing; and

(d) if at any time the heater is operated in excess of the highest achievable load plus ten percent, the owner or operator shall perform the testing specified in Subparagraph (a) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC within 60 days from the anomalous operation.

(3) When conducting periodic testing of a heater, the owner or operator shall follow the procedures in Paragraph (2) of Subsection C of 20.2.50.119 NMAC. An owner or operator may deviate from those procedures by submitting a written request to use an alternative procedure to the department at least 60 days before performing the periodic testing. In the alternative procedure request, the owner or operator must demonstrate the alternative procedure's equivalence to the standard procedure. The owner or operator must receive written approval from the department prior to conducting the periodic testing using an alternative procedure.

(4) Prior to a monitoring, inspection, maintenance, or repair event, the owner or operator shall scan the EMT and the required monitoring data shall be captured in accordance with this Part.

D. Recordkeeping requirements: The owner or operator shall maintain a record of the following:

(1) location of the heater;

(2) summary of the complete test report and the results of periodic testing; and

(3) inspections, testing, maintenance, and repairs, which shall include at a minimum:

(a) the date the inspection, testing, maintenance, or repair was conducted;

(b) name of the personnel conducting the inspection, testing, maintenance, or repair;

(c) concentrations in the effluent stream of CO in ppmv and O₂ in volume percent;

and

(d) the results of the inspections and any the corrective action taken.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.119 NMAC - N, XX/XX/2021]

20.2.50.120 HYDROCARBON LIQUID TRANSFERS:

A. Applicability: Hydrocarbon liquid transfers located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, or transmission-natural gas compressor stations are subject to the requirements of 20.2.50.120 NMAC beginning one year from the effective date of this Part.

B. Emission standards:

(1) The owner or operator of a hydrocarbon liquid transfer operation shall use vapor balance

or, vapor recovery to control VOC emissions by 100%, or a control device to control VOC emissions by at least ninety-eight percent, when transferring liquid from a storage vessel to a transfer vessel, or when transferring liquid from a transfer vessel to a storage vessel.

(2) An owner or operator using vapor balance during a liquid transfer operation shall:

(a) transfer the vapor displaced from the vessel being loaded back to the vessel being emptied via a pipe or hose connected before the start of the transfer operation;

(b) ensure that the transfer does not begin until the vapor collection and return system is properly connected;

(c) ensure that connector pipes, hoses, couplers, valves, and pressure relief devices are maintained in a leak-free condition;

(d) check the liquid and vapor line connections for proper connections before commencing the transfer operation; and

(e) operate transfer equipment at a pressure that is less than the pressure relief valve setting of the receiving transport vehicle or storage vessel.

(3) Bottom loading or submerged filling shall be used for the liquid transfer.

(4) Connector pipes and couplers shall be maintained in a leak-free condition.

(5) Connections of hoses and pipes used during liquid transfer operations shall be supported on drip trays that collect any leaks, and the materials collected shall be returned to the process or disposed of in a manner compliant with state law.

(6) Liquid leaks that occur shall be cleaned and disposed of in a manner that prevents minimizes emissions to the atmosphere, and the material collected shall be returned to the process or disposed of in a manner compliant with state law.

(7) An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.120 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator shall visually inspect the transfer equipment during a transfer operation to ensure that liquid transfer lines, hoses, couplings, valves, and pipes are not dripping or leaking. Leaking components shall be repaired to prevent dripping or leaking before the next transfer operation.

(2) The owner or operator of a liquid transfer operation controlled by a control device must follow manufacturer recommended operation and maintenance procedures for the device.

~~(3) Tanker trucks and tanker rail cars used in liquid transfer service shall be tested annually for vapor tightness in accordance with the following test methods and vapor tightness standards:~~

~~(a) method 27 of appendix A of 40 CFR Part 60. Conduct the test using a time period (t) for the pressure and vacuum tests of five minutes. The initial pressure (Pi) for the pressure test shall be 460 mm H₂O (18 inches H₂O), gauge. The initial vacuum (Vi) for the vacuum test shall be 150 mm H₂O (six inches H₂O) gauge. The maximum allowable pressure and vacuum changes (Δp, Δv) are shown in table 1 of 20.2.50.120 NMAC.~~

Table 1—ALLOWABLE CARGO TANK TEST PRESSURE OR VACUUM CHANGE

Cargo tank or compartment capacity, liters (gallons)	Allowable vacuum change (Δv) in five minutes, mm H ₂ O (inches H ₂ O)	Allowable pressure change (Δp) in five minutes, mm H ₂ O (inches H ₂ O)
<3,785 (<1,000)	64 (2.5)	102 (4.0)
3,785 < 5,678 (1,000 < 1,500)	51 (2.0)	89 (3.5)
5,678 < 9,464 (1,500 < 2,500)	38 (1.5)	76 (3.0)
>9,464 (>2,500)	25 (1.0)	64 (2.5)

~~(b) pressure test the tanker truck or tanker railcar tank's internal vapor valve as follows:~~

~~(i) after completing the tests under Subparagraph (a) of Paragraph (3) of Subsection C of 20.2.50.120 NMAC, use the procedures in method 27 to re-pressurize the tank to 460 mm H₂O (18 inches H₂O) gauge. Close the tank's internal vapor valve, thereby isolating the vapor return line and manifold from the tank.~~

~~(ii) relieve the pressure in the vapor return line to atmospheric pressure, then re-seal the line. After five minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable five-minute pressure increase is 130 mm H₂O (five inches H₂O).~~

(34) Owners and operators complying with Paragraph (1) of Subsection B of 20.2.50.120

NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.
(45) Owners and operators shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain a record of the location of the storage vessel and if using a control device, the type, make, and model of the control device.

(2) The owner or operator shall maintain a record of the inspections and testing required in Subsection C of 20.2.50.120 NMAC and shall include the following:

- (a) the time and date of the inspection and testing;
- (b) the name of the personnel conducting the inspection and testing;
- (c) a description of any problem observed during the inspection and testing; and
- (d) the results of the inspection and testing and a description of any repair or corrective action taken.

(3) The owner or operator shall maintain a record for each site of the annual total hydrocarbon liquid transferred and annual total VOC emissions. Each calendar year, the owner or operator shall create a company-wide record summarizing the annual total hydrocarbon liquid transferred and the annual total calculated VOC emissions.

(4) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.120 NMAC - N, XX/XX/2021]

20.2.50.121 PIG LAUNCHING AND RECEIVING:

A. Applicability: Pipeline pig launching and receiving operations located within or outside of the property boundary of wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission-natural gas compressor stations are subject to the requirements of 20.2.50.121 NMAC.

B. Emission standards:

(1) Owners and operators of pipeline pig launching and receiving operations with a PTE equal to or greater than one tpy of VOC shall capture and reduce VOC emissions by at least ninety-eight percent, beginning on the effective date of this Part.

(2) The owner or operator conducting the pig launching and receiving operation shall:

- (a) employ best management practices to minimize the liquid present in the pig receiver chamber and to prevent emissions from the pig receiver chamber to the atmosphere after receiving the pig in the receiving chamber and before opening the receiving chamber to the atmosphere;
- (b) employ a method to prevent emissions, such as installing a liquid ramp or drain, routing a high-pressure chamber to a low-pressure line or vessel, using a ball valve type chamber, or using multiple pig chambers;

(c) recover and dispose of receiver liquid in a manner that prevents emissions to the atmosphere; and

(d) ensure that the material collected is returned to the process or disposed of in a manner compliant with state law.

(3) The emission standards in Paragraphs (1) and (2) of Subsection B of 20.2.50.121 NMAC cease to apply to a pipeline pig launching and receiving operation if the uncontrolled actual annual VOC emissions of the operation are less than one half ton per year of VOC.

(4) An owner or operator complying with Paragraph (2) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator of pig launching and receiving operations shall monitor the type and volume of liquid cleared.

(2) The owner or operator of pig launching and receiving operations shall inspect the equipment for a leak using RM 21 or OGI immediately before the commencement and immediately after the conclusion of the pig launching or receiving operation, and according to the requirements in 20.2.50.116 NMAC.

(3) An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) The owner or operator shall comply with the monitoring requirements in 20.2.50.112

NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of pig launching and receiving operations shall maintain a record of the following:

(a) the pigging operation, including the date and time of the pigging operation and the type and volume of liquid cleared;

(b) the data and methodology used to estimate the actual emissions to the atmosphere and used to estimate the PTE; and

(c) the type of control device and its location, make, and model.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.121 NMAC - N, XX/XX/2021]

20.2.50.122 PNEUMATIC CONTROLLERS AND PUMPS:

A. Applicability: Natural gas-driven pneumatic controllers and pumps located at wellhead sites, tank batteries, gathering and boosting ~~sites~~stations, natural gas processing plants, ~~and~~and natural gas compressor stations ~~transmission compressor stations~~ are subject to the requirements of 20.2.50.122 NMAC.

B. Emission standards:

(1) A new natural gas-driven pneumatic controller or pump shall comply with the requirements of 20.2.50.122 NMAC upon startup.

(2) An existing natural gas-driven pneumatic pump shall comply with the requirements of 20.2.50.122 NMAC within three years of the effective date of this Part.

(3) An existing natural gas-driven pneumatic controller shall comply with the requirements of 20.2.50.122 NMAC according to the following schedule:

Table 1 – WELLHEAD SITES, TANK BATTERIES, GATHERING AND BOOSTING ~~FACILITIES~~STATIONS

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
> 75 %	80%	85%	90%
> 60-75 %	80%	85%	90%
> 40-60 %	65%	70%	80%
> 20-40 %	45%	70%	80%
0-20 %	25%	65%	80%

Table 2 – NATURAL GAS COMPRESSOR STATIONS AND GAS PROCESSING PLANTS

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
> 75 %	80%	95%	98%
> 60-75 %	80%	95%	98%
> 40-60 %	65%	95%	98%
> 20-40 %	50%	95%	98%
0-20 %	35%	95%	98%

(4) Standards for natural gas-driven pneumatic controllers.

(a) new pneumatic controllers shall have an emission rate of zero.

(b) existing pneumatic controllers with access to commercial line electrical power shall have an emission rate of zero.

(c) existing pneumatic controllers shall meet the required percentage of non-emitting controllers within the deadlines in tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC,

1 and shall comply with the following:

2 (i) by January 1, 2023, the owner or operator shall determine the total
3 controller count for all controllers at all of the owner or operator's affected facilities that commenced construction
4 before the effective date of this Part. The total controller count must include all emitting pneumatic controllers and
5 all non-emitting pneumatic controllers, except that pneumatic controllers necessary for a safety or process purpose
6 that cannot otherwise be met without emitting natural gas shall not be included in the total controller count.

7 (ii) determine which controllers in the total controller count are non-
8 emitting and sum the total number of non-emitting controllers and designate those as total historic non-emitting
9 controllers.

10 (iii) determine the total historic non-emitting percent of controllers by
11 dividing the total historic non-emitting controller count by the total controller count and multiplying by 100.

12 (iv) based on the percent calculated in (iii) above, the owner or operator
13 shall determine which provisions of tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC apply
14 and the replacement schedule the owner or operator must meet.

15 (v) if an owner or operator meets at least seventy-five percent total non-
16 emitting controllers by January 1, 2025, the owner or operator ~~is not subject to~~ ~~has satisfied~~ the requirements of
17 tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC.

18 (vi) if after January 1, 2027, an owner or operator's remaining pneumatic
19 controllers are not cost-effective to retrofit, the owner or operator shall submit a cost analysis of retrofitting those
20 remaining units to the department. The department shall review the cost analysis and determine whether those units
21 qualify for a waiver from meeting additional retrofit requirements.

22 (d) a pneumatic controller with a bleed rate greater than six standard cubic feet per
23 hour is permitted when the owner or operator has demonstrated that a higher bleed rate is required based on
24 functional needs, including response time, safety, and positive actuation. An owner or operator that seeks to
25 maintain operation of an emitting pneumatic controller must prepare and document the justification for the safety or
26 process purposes prior to the installation of a new emitting controller or the retrofit of an existing controller. The
27 justification shall be certified by a qualified professional engineer.

28 (5) Standards for natural gas-driven pneumatic pumps.

29 (a) pneumatic pumps located at a natural gas processing plants shall have an
30 emission rate of zero.

31 (b) pneumatic pumps located at a wellhead sites, tank batteries, gathering and
32 boosting ~~sites~~ ~~stations~~, or ~~transmission-natural gas~~ compressor stations with access to commercial line electrical
33 power shall have an emission rate of zero.

34 (c) owners and operators of pneumatic pumps located at wellhead sites, tank
35 batteries, gathering and boosting ~~sites~~ ~~stations~~, or ~~transmission-natural gas~~ compressor stations without access to
36 commercial line electrical power shall reduce VOC emissions from the pneumatic pumps by ninety-five percent if it
37 is technically feasible to route emissions to a control device, fuel cell, or process. If there is a control device
38 available onsite but it is unable to achieve a ninety-five percent emission reduction, and it is not technically feasible
39 to route the pneumatic pump emissions to a fuel cell or process, the owner or operator shall route the pneumatic
40 pump emissions to the control device.

41 (6) The owner or operator of a pneumatic controller or pump shall install an EMT on the
42 controller or pump in accordance with 20.2.50.112 NMAC.

43 **C. Monitoring requirements:**

44 (1) Pneumatic controllers or pumps with a natural gas bleed rate equal to zero are not subject
45 to the monitoring requirements in Subsection C of 20.2.5.122 NMAC.

46 (2) The owner or operator of a pneumatic controller subject to the deadlines set forth in
47 tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC shall monitor the compliance status of each
48 subject controller at each facility.

49 (3) The owner or operator of a pneumatic controller with a bleed rate greater than zero shall,
50 on a monthly basis, scan the controller and conduct an AVO inspection, and shall also inspect the pneumatic
51 controller, perform necessary maintenance (such as cleaning, tuning, and repairing a leaking gasket, tubing fitting
52 and seal; tuning to operate over a broader range of proportional band; eliminating an unnecessary valve positioner),
53 and maintain the pneumatic controller according to manufacturer specifications to ensure that the VOC emissions
54 are minimized.

55 (4) The EMT shall be linked to a database that contains the following:

56 (a) pneumatic controller identification number;

(b) type of controller (continuous or intermittent);
 (c) if continuous, design continuous bleed rate in standard cubic feet per hour;
 (d) if intermittent, bleed volume per intermittent bleed in standard cubic feet; and
 (e) design annual bleed in standard cubic feet per year.
 (5) The owner or operator of a pneumatic pump with a bleed rate greater than zero shall, on a monthly basis, scan the pump and conduct an AVO inspection and shall also inspect the pneumatic pump and perform necessary maintenance, and maintain the pneumatic pump according to manufacturer specifications to ensure that the VOC emissions are minimized.

(6) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) Pneumatic controllers and pumps with a natural gas bleed rate equal to zero are not subject to the recordkeeping requirements in Subsection D of 20.2.5.122 NMAC.

(2) The owner or operator shall maintain a record of the total controller count for all controllers at all of the owner's or operator's affected facilities that commenced operation before the effective date of this Part. The total controller count must include all emitting and non-emitting pneumatic controllers.

(3) The owner or operator shall maintain a record of the total count of pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting VOC.

(4) The owner or operator of a pneumatic controller subject to the requirements in tables 1 and 2 of Paragraph (3) of shall generate a schedule for meeting the compliance deadlines for each pneumatic controller. The owner or operator shall keep a record of the compliance status of each subject controller.

(5) The owner or operator shall maintain an electronic record for each pneumatic controller with a natural gas bleed rate greater than zero. The record shall include the following:

(a) pneumatic controller identification number;
 (b) inspection dates;
 (c) name of the personnel conducting the inspection;
 (d) AVO inspection result;
 (e) AVO level discrepancy in continuous or intermittent bleed rate;
 (f) maintenance date and maintenance activity; and
 (g) a record of the justification and certification required in Subparagraph (d) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC.

(6) The owner or operator of a natural gas-driven pneumatic controller with a bleed rate greater than six standard cubic feet per hour shall maintain a record in the EMT database of the pneumatic controller documenting why a bleed rate greater than six scf/hr is necessary, as required in Subsection B of 20.2.50.122 NMAC.

(7) The owner or operator shall maintain a record in the EMT database for a natural gas-driven pneumatic pump with an emission rate greater than zero and the associated pump number at the facility. The record shall include:

(a) for a natural gas-driven pneumatic pump in operation less than 90 days per calendar year, a record for each day of operation during the calendar year.
 (b) a record of any control device designed to achieve at least a ninety-five percent emission reduction, including an evaluation or manufacturer specifications indicating the percentage reduction the control device is designed to achieve.
 (c) records of the engineering assessment and certification by a qualified professional engineer that routing pneumatic pump emissions to a control device, fuel cell, or process is technically infeasible.

(8) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
 [20.2.50.122 NMAC - N, XX/XX/2021]

20.2.50.123 STORAGE VESSELS

A. Applicability: Storage vessels with an uncontrolled PTE equal to or greater than two tpy of VOC and located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, or transmission-natural gas compressor stations are subject to the requirements of 20.2.50.123 NMAC.

B. Emission standards:

(1) An existing storage vessel with a PTE equal to or greater than two tpy and less than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-five percent no later than three years after the effective date of this Part.

(2) An existing storage vessel with a PTE equal to or greater than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-eight percent no later than one year after the effective date of this Part.

(3) A new storage vessel with a PTE equal to or greater than two tpy and less than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-five percent upon startup.

(4) A new storage vessel with a PTE equal to or greater than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-eight percent upon startup.

(5) The emission standards in Subsection B of 20.2.50.123 NMAC cease to apply to a storage vessel if the uncontrolled actual annual VOC emissions decrease to less than two tpy.

(6) If a control device is not installed by the date specified in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC, an owner or operator may comply with Subsection B of 20.2.50.123 NMAC by shutting in the well supplying the storage vessel by the applicable date, and not resuming production from the well until the control device is installed and operational.

(7) The owner or operator of a new or existing storage vessel with a thief hatch shall install a control device that allows the thief hatch to open sufficiently to relieve overpressure in the vessel and to automatically close once the vessel overpressure is relieved. The thief hatch shall be equipped with a manual lock-open safety device to ensure positive hatch opening during times of human ingress. The lock-open safety device shall only be engaged when an owner or operator are present and during an active ingress activity.

(8) The owner or operator of a new or existing storage vessel shall install an EMT on the storage vessel in accordance with 20.2.50.112 NMAC.

(9) An owner or operator complying with Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the control device operational requirements in 20.2.50.115 NMAC.

C. Monitoring requirements: The owner or operator of a storage vessel shall:

(1) monitor on a monthly basis the total monthly liquid throughput (in barrels) and the upstream separator pressure (in psig). When a storage vessel is unloaded less frequently than monthly, the throughput and separator pressure monitoring shall be conducted before the storage vessel is unloaded;

(2) conduct an AVO inspection on a weekly basis. If the storage vessel is unloaded less frequently than weekly, the AVO inspection shall be conducted before the storage vessel is unloaded;

(3) inspect the vessel monthly to ensure compliance with the requirements of 20.2.50.123 NMAC. The inspection shall include a check to ensure the vessel does not have a leak;

(4) scan the EMT and enter the required monitoring data in accordance with the requirements of 20.2.50.112 NMAC;

(5) comply with the monitoring requirements in 20.2.50.115 NMAC if using a control device to comply with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC; and

(6) comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall, on a monthly basis, maintain a record in accordance with 20.2.50.112 NMAC for a storage vessel. The record shall include:

(a) the vessel location and identification number;

(b) monthly liquid throughput and the most recent date of measurement;

(c) the average monthly upstream separator pressure;

(d) the data and methodology used to calculate the PTE of VOC (the calculation methodology shall be department approved);

(e) the controlled and uncontrolled VOC emissions (tpy); and

(f) the type, make, model, and identification number of any control device.

(2) A record of liquid throughput ~~in~~ shall be verified by a dated delivery receipt from the purchaser of the hydrocarbon liquid, the metered volume of hydrocarbon liquid sent downstream, or other proof of transfer.

(3) A record of the inspection required in Subsection C of 20.2.50.123 NMAC shall include:

(a) the time and date of the inspection;

(b) the personnel conducting the inspection;

(c) a notation that the required leak check was completed;
 (d) a description of any problem observed during the inspection; and
 (e) a description and date of any corrective action taken.
 (4) An owner or operator complying with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(5) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements:

(1) An owner or operator complying with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the reporting requirements in 20.2.50.15 NMAC.

(2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.123 NMAC - N, XX/XX/2021]

20.2.50.124 WELL WORKOVERS

A. Applicability: Workovers performed at oil and natural gas wells are subject to the requirements of 20.2.50.124 NMAC as of the effective date of this Part.

B. Emission standards: The owner or operator of an oil or natural gas well shall use the following best management practices during a workover to minimize emissions, consistent with the well site condition and good engineering practices:

(1) reduce wellhead pressure before blowdown to minimize the volume of natural gas vented;

(2) monitor manual venting at the well until the venting is complete; and

(3) route natural gas to the sales line, if possible.

C. Monitoring requirements:

(1) The owner or operator shall monitor the following parameters during a workover:

(a) wellhead pressure;

(b) flow rate of the vented natural gas (to the extent feasible); and

(c) duration of venting to the atmosphere.

(2) The owner or operator shall calculate the volume and mass of VOC vented during a workover.

(3) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall keep the following record for a workover:

(a) identification number and location of the well;

(b) date the workover was performed;

(c) wellhead pressure;

(d) flow rate of the vented natural gas to the extent feasible, and if measurement of the flow rate is not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation;

(e) duration of venting to the atmosphere;

(f) description of the management practices used to minimize release of VOC before and during the workover; and

(g) calculation of the VOC emissions vented during the workover based on the duration, volume, and mass of VOC.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements

(1) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

(2) If it is not feasible to prevent VOC emissions from being emitted to the atmosphere from a workover event, the owner or operator shall notify by certified mail all residents located within one-quarter mile of the well of the planned workover at least three calendar days before the workover event.

[20.2.50.124 NMAC - N, XX/XX/2021]

20.2.50.125 SMALL BUSINESS FACILITIES

A. Applicability: Small business facilities as defined in this Part are subject to the requirements of 20.2.50.125 NMAC.

B. General requirements:

(1) The owner or operator shall ensure that all equipment is operated and maintained consistent with manufacturer specifications, and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available to the department upon request.

(2) The owner or operator shall calculate the VOC and NO_x emissions from the facility on an annual basis. The calculation shall be based on the actual production or processing rates of the facility.

(3) The owner or operator shall maintain a database of company-wide VOC and NO_x emission calculations for all subject facilities and associated equipment and shall update the database annually.

(4) The owner or operator shall comply with Paragraph (10) of Subsection A of 20.2.50.112 NMAC if requested by the department.

C. Monitoring requirements: The owner or operator shall comply with the requirements in Subsections C or D of 20.2.50.116 NMAC.

D. Repair requirements: The owner or operator shall comply with the requirements of Subsection E of 20.2.50.116 NMAC.

E. Recordkeeping requirements: The owner or operator shall maintain the following electronic records for each facility:

- (1) annual certification that the small business facility meets the definition in this Part;
- (2) calculated VOC and NO_x emissions from each facility and the company-wide VOC and NO_x emissions for all subject facilities;
- (3) records as required under Subsection F of 20.2.50.116 NMAC.

F. Reporting requirements: The owner or operator shall submit to the department an initial small business certification within sixty days of the effective date of this Part, and by March 1 each calendar year thereafter. The certification shall be made on a form provided by the department. The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

G. Failure to comply with 20.2.50.125 NMAC: Notwithstanding the provisions of Section 20.2.50.125 NMAC, a source that meets the definition of a small business facility can be required to comply with the other Sections of 20.2.50 NMAC if the Secretary finds based on credible evidence that the source (1) presents an imminent and substantial endangerment to the public health or welfare or to the environment; (2) is not being operated or maintained in a manner that minimizes emissions of air contaminants; or (3) has violated any other requirement of 20.2.50.125 NMAC.

[20.2.50.125 NMAC - N, XX/XX/2021]

20.2.50.126 PRODUCED WATER MANAGEMENT UNITS

A. Applicability: Produced water management units as defined in this Part are subject to 20.2.50.126 NMAC and shall comply with these requirements no later than 180 days after the effective date of this Part.

B. Emission standards:

(1) The owner or operator shall use best management and good engineering practices to minimize emissions of VOC from produced water management units.

(2) The owner or operator shall control VOC emissions from each produced water management unit to less than two tons per year.

C. Monitoring requirements: The owner or operator shall:

- (1) calculate the monthly rolling 12-month total of VOC emissions in tons from each unit;
- (2) monthly, monitor the best management and engineering practices implemented to reduce emissions at each unit to ensure their effectiveness; and
- (3) comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain the following electronic records for each produced water management unit:

- (a) name or identification of the unit and UTM coordinates of the unit and county;

1 (b) a description of the best management and engineering practices used to
2 minimize release of VOC at the unit; and
3 (c) a record of the monthly rolling 12-month total VOC emissions from each unit.
4 (2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112
5 NMAC.

6 E. **Reporting requirements:** The owner or operator shall comply with the reporting requirements in
7 20.2.50.112 NMAC.
8 [20.2.50.126 NMAC - N, XX/XX/2021]
9

10 **20.2.50.127 PROHIBITED ACTIVITY AND CREDIBLE INFORMATION PRESUMPTION**

11 A. Failure to comply with the emissions standards, monitoring, recordkeeping, reporting or other
12 requirements of this Part within the timeframes specified shall constitute a violation of this Part subject to
13 enforcement action under Section 74-2-12 NMSA 1978.

14 B. If credible information obtained by the department indicates that a source is not in compliance
15 with the provisions of this Part, the source shall be presumed to be in violation of this Part unless and until the owner
16 or operator provides credible evidence or information demonstrating otherwise.

17 C. If credible information provided to the department by a member of the public indicates that a
18 source is not in compliance with the provisions of this Part, the source shall be presumed to be in violation of this
19 Part unless and until the owner or operator provides credible evidence or information demonstrating otherwise.
20 [20.2.50.127 NMAC - N, XX/XX/2021]
21

22 **HISTORY OF 20.2.50 NMAC: [RESERVED]**

While we have taken steps to ensure the accuracy of this Internet version of the document, it is not the official version. To see a complete version including any recent edits, visit: <https://www.ecfr.gov/cgi-bin/ECFR?page=browse> and search under Title 40, Protection of Environment.

METHOD 21 - DETERMINATION OF VOLATILE ORGANIC COMPOUND LEAKS

1.0 Scope and Application

1.1 Analytes.

Analyte	CAS No.
Volatile Organic Compounds (VOC)	No CAS number assigned.

1.2 Scope. This method is applicable for the determination of VOC leaks from process equipment. These sources include, but are not limited to, valves, flanges and other connections, pumps and compressors, pressure relief devices, process drains, open-ended valves, pump and compressor seal system degassing vents, accumulator vessel vents, agitator seals, and access door seals.

1.3 Data Quality Objectives. Adherence to the requirements of this method will enhance the quality of the data obtained from air pollutant sampling methods.

2.0 Summary of Method

2.1 A portable instrument is used to detect VOC leaks from individual sources. The instrument detector type is not specified, but it must meet the specifications and performance criteria contained in Section 6.0. A leak definition concentration based on a reference compound is specified in each applicable regulation. This method is intended to locate and classify leaks only, and is not to be used as a direct measure of mass emission rate from individual sources.

3.0 Definitions

3.1 *Calibration gas* means the VOC compound used to adjust the instrument meter reading to a known value. The calibration gas is usually the reference compound at a known concentration approximately equal to the leak definition concentration.

3.2 *Calibration precision* means the degree of agreement between measurements of the same known value, expressed as the relative percentage of the average difference between the meter readings and the known concentration to the known concentration.

3.3 *Leak definition concentration* means the local VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is present. The leak definition is an instrument meter reading based on a reference compound.

3.4 *No detectable emission* means a local VOC concentration at the surface of a leak source, adjusted for local VOC ambient concentration, that is less than 2.5 percent of the specified leak definition concentration. that indicates that a VOC emission (leak) is not present.

3.5 *Reference compound* means the VOC species selected as the instrument calibration basis for specification of the leak definition concentration. (For example, if a leak definition concentration is 10,000 ppm as methane, then any source emission that results in a local concentration that yields a meter reading of 10,000 on an instrument meter calibrated with methane would be classified as a leak. In this example, the leak definition concentration is 10,000 ppm and the reference compound is methane.)

3.6 *Response factor* means the ratio of the known concentration of a VOC compound to the observed meter reading when measured using an instrument calibrated with the reference compound specified in the applicable regulation.

3.7 *Response time* means the time interval from a step change in VOC concentration at the input of the sampling system to the time at which 90 percent of the corresponding final value is reached as displayed on the instrument readout meter.

4.0 *Interferences[Reserved]*

5.0 *Safety*

5.1 Disclaimer. This method may involve hazardous materials, operations, and equipment. This test method may not address all of the safety problems associated with its use. It is the responsibility of the user of this test method to establish appropriate safety and health practices and determine the applicability of regulatory limitations prior to performing this test method.

5.2 Hazardous Pollutants. Several of the compounds, leaks of which may be determined by this method, may be irritating or corrosive to tissues (*e.g.*, heptane) or may be toxic (*e.g.*, benzene, methyl alcohol). Nearly all are fire hazards. Compounds in emissions should be determined through familiarity with the source. Appropriate precautions can be found in reference documents, such as reference No. 4 in Section 16.0.

6.0 *Equipment and Supplies*

A VOC monitoring instrument meeting the following specifications is required:

6.1 The VOC instrument detector shall respond to the compounds being processed. Detector types that may meet this requirement include, but are not limited to, catalytic oxidation, flame ionization, infrared absorption, and photoionization.

6.2 The instrument shall be capable of measuring the leak definition concentration specified in the regulation.

6.3 The scale of the instrument meter shall be readable to ± 2.5 percent of the specified leak definition concentration.

6.4 The instrument shall be equipped with an electrically driven pump to ensure that a sample is provided to the detector at a constant flow rate. The nominal sample flow rate, as measured at the sample probe tip, shall be 0.10 to 3.0 l/min (0.004 to 0.1 ft³/min) when the probe is fitted with a glass wool plug or filter that may be used to prevent plugging of the instrument.

6.5 The instrument shall be equipped with a probe or probe extension or sampling not to exceed 6.4 mm (1/4in) in outside diameter, with a single end opening for admission of sample.

6.6 The instrument shall be intrinsically safe for operation in explosive atmospheres as defined by the National Electrical Code by the National Fire Prevention Association or other applicable regulatory code for operation in any explosive atmospheres that may be encountered in its use. The instrument shall, at a minimum, be intrinsically safe for Class 1, Division 1 conditions, and/or Class 2, Division 1 conditions, as appropriate, as defined by the example code. The instrument shall not be operated with any safety device, such as an exhaust flame arrestor, removed.

7.0 Reagents and Standards

7.1 Two gas mixtures are required for instrument calibration and performance evaluation:

7.1.1 Zero Gas. Air, less than 10 parts per million by volume (ppmv) VOC.

7.1.2 Calibration Gas. For each organic species that is to be measured during individual source surveys, obtain or prepare a known standard in air at a concentration approximately equal to the applicable leak definition specified in the regulation.

7.2 Cylinder Gases. If cylinder calibration gas mixtures are used, they must be analyzed and certified by the manufacturer to be within 2 percent accuracy, and a shelf life must be specified. Cylinder standards must be either reanalyzed or replaced at the end of the specified shelf life.

7.3 Prepared Gases. Calibration gases may be prepared by the user according to any accepted gaseous preparation procedure that will yield a mixture accurate to within 2 percent. Prepared standards must be replaced each day of use unless it is demonstrated that degradation does not occur during storage.

7.4 Mixtures with non-Reference Compound Gases. Calibrations may be performed using a compound other than the reference compound. In this case, a conversion factor must be determined for the alternative compound such that the resulting meter readings during source surveys can be converted to reference compound results.

8.0 Sample Collection, Preservation, Storage, and Transport

8.1 Instrument Performance Evaluation. Assemble and start up the instrument according to the manufacturer's instructions for recommended warm-up period and preliminary adjustments.

8.1.1 Response Factor. A response factor must be determined for each compound that is to be measured, either by testing or from reference sources. The response factor tests are required before placing the analyzer into service, but do not have to be repeated at subsequent intervals.

8.1.1.1 Calibrate the instrument with the reference compound as specified in the applicable regulation. Introduce the calibration gas mixture to the analyzer and record the observed meter reading. Introduce zero gas until a stable reading is obtained. Make a total of three measurements by alternating between the calibration gas and zero gas. Calculate the response factor for each repetition and the average response factor.

8.1.1.2 The instrument response factors for each of the individual VOC to be measured shall be less than 10 unless otherwise specified in the applicable regulation. When no instrument is available that meets this specification when calibrated with the reference VOC specified in the applicable regulation, the available instrument may be calibrated with one of the VOC to be measured, or any other VOC, so long as the instrument then has a response factor of less than 10 for each of the individual VOC to be measured.

8.1.1.3 Alternatively, if response factors have been published for the compounds of interest for the instrument or detector type, the response factor determination is not required, and existing results may be referenced. Examples of published response factors for flame ionization and catalytic oxidation detectors are included in References 1–3 of Section 17.0.

8.1.2 Calibration Precision. The calibration precision test must be completed prior to placing the analyzer into service and at subsequent 3-month intervals or at the next use, whichever is later.

8.1.2.1 Make a total of three measurements by alternately using zero gas and the specified calibration gas. Record the meter readings. Calculate the average algebraic difference between the meter readings and the known value. Divide this average difference by the known calibration value and multiply by 100 to express the resulting calibration precision as a percentage.

8.1.2.2 The calibration precision shall be equal to or less than 10 percent of the calibration gas value.

8.1.3 Response Time. The response time test is required before placing the instrument into service. If a modification to the sample pumping system or flow configuration is made that would change the response time, a new test is required before further use.

8.1.3.1 Introduce zero gas into the instrument sample probe. When the meter reading has stabilized, switch quickly to the specified calibration gas. After switching, measure the time required to attain 90 percent of the final stable reading. Perform this test sequence three times and record the results. Calculate the average response time.

8.1.3.2 The instrument response time shall be equal to or less than 30 seconds. The instrument pump, dilution probe (if any), sample probe, and probe filter that will be used during testing shall all be in place during the response time determination.

8.2 Instrument Calibration. Calibrate the VOC monitoring instrument according to Section 10.0.

8.3 Individual Source Surveys.

8.3.1 Type I—Leak Definition Based on Concentration. Place the probe inlet at the surface of the component interface where leakage could occur. Move the probe along the interface periphery while observing the instrument readout. If an increased meter reading is observed, slowly sample the interface where leakage is indicated until the maximum meter reading is obtained. Leave the probe inlet at this maximum reading location for approximately two times the instrument response time. If the maximum observed meter reading is greater than the leak definition in the applicable regulation, record and report the results as specified in the regulation reporting requirements. Examples of the application of this general technique to specific equipment types are:

8.3.1.1 Valves. The most common source of leaks from valves is the seal between the stem and housing. Place the probe at the interface where the stem exits the packing gland and sample the stem circumference. Also, place the probe at the interface of the packing gland take-up flange seat and sample

the periphery. In addition, survey valve housings of multipart assembly at the surface of all interfaces where a leak could occur.

8.3.1.2 Flanges and Other Connections. For welded flanges, place the probe at the outer edge of the flange-gasket interface and sample the circumference of the flange. Sample other types of nonpermanent joints (such as threaded connections) with a similar traverse.

8.3.1.3 Pumps and Compressors. Conduct a circumferential traverse at the outer surface of the pump or compressor shaft and seal interface. If the source is a rotating shaft, position the probe inlet within 1 cm of the shaft-seal interface for the survey. If the housing configuration prevents a complete traverse of the shaft periphery, sample all accessible portions. Sample all other joints on the pump or compressor housing where leakage could occur.

8.3.1.4 Pressure Relief Devices. The configuration of most pressure relief devices prevents sampling at the sealing seat interface. For those devices equipped with an enclosed extension, or horn, place the probe inlet at approximately the center of the exhaust area to the atmosphere.

8.3.1.5 Process Drains. For open drains, place the probe inlet at approximately the center of the area open to the atmosphere. For covered drains, place the probe at the surface of the cover interface and conduct a peripheral traverse.

8.3.1.6 Open-ended Lines or Valves. Place the probe inlet at approximately the center of the opening to the atmosphere.

8.3.1.7 Seal System Degassing Vents and Accumulator Vents. Place the probe inlet at approximately the center of the opening to the atmosphere.

8.3.1.8 Access door seals. Place the probe inlet at the surface of the door seal interface and conduct a peripheral traverse.

8.3.2 Type II—"No Detectable Emission". Determine the local ambient VOC concentration around the source by moving the probe randomly upwind and downwind at a distance of one to two meters from the source. If an interference exists with this determination due to a nearby emission or leak, the local ambient concentration may be determined at distances closer to the source, but in no case shall the distance be less than 25 centimeters. Then move the probe inlet to the surface of the source and determine the concentration as outlined in Section 8.3.1. The difference between these concentrations determines whether there are no detectable emissions. Record and report the results as specified by the regulation. For those cases where the regulation requires a specific device installation, or that specified vents be ducted or piped to a control device, the existence of these conditions shall be visually confirmed. When the regulation also requires that no detectable emissions exist, visual observations and sampling surveys are required. Examples of this technique are:

8.3.2.1 Pump or Compressor Seals. If applicable, determine the type of shaft seal. Perform a survey of the local area ambient VOC concentration and determine if detectable emissions exist as described in Section 8.3.2.

8.3.2.2 Seal System Degassing Vents, Accumulator Vessel Vents, Pressure Relief Devices. If applicable, observe whether or not the applicable ducting or piping exists. Also, determine if any sources exist in the ducting or piping where emissions could occur upstream of the control device. If the required ducting or piping exists and there are no sources where the emissions could be vented to the atmosphere upstream of

the control device, then it is presumed that no detectable emissions are present. If there are sources in the ducting or piping where emissions could be vented or sources where leaks could occur, the sampling surveys described in Section 8.3.2 shall be used to determine if detectable emissions exist.

8.3.3 Alternative Screening Procedure.

8.3.3.1 A screening procedure based on the formation of bubbles in a soap solution that is sprayed on a potential leak source may be used for those sources that do not have continuously moving parts, that do not have surface temperatures greater than the boiling point or less than the freezing point of the soap solution, that do not have open areas to the atmosphere that the soap solution cannot bridge, or that do not exhibit evidence of liquid leakage. Sources that have these conditions present must be surveyed using the instrument technique of Section 8.3.1 or 8.3.2.

8.3.3.2 Spray a soap solution over all potential leak sources. The soap solution may be a commercially available leak detection solution or may be prepared using concentrated detergent and water. A pressure sprayer or squeeze bottle may be used to dispense the solution. Observe the potential leak sites to determine if any bubbles are formed. If no bubbles are observed, the source is presumed to have no detectable emissions or leaks as applicable. If any bubbles are observed, the instrument techniques of Section 8.3.1 or 8.3.2 shall be used to determine if a leak exists, or if the source has detectable emissions, as applicable.

9.0 Quality Control

Section	Quality control measure	Effect
8.1.2	Instrument calibration precision check	Ensure precision and accuracy, respectively, of instrument response to standard.
10.0	Instrument calibration	

10.0 Calibration and Standardization

10.1 Calibrate the VOC monitoring instrument as follows. After the appropriate warm-up period and zero internal calibration procedure, introduce the calibration gas into the instrument sample probe. Adjust the instrument meter readout to correspond to the calibration gas value.

Note: If the meter readout cannot be adjusted to the proper value, a malfunction of the analyzer is indicated and corrective actions are necessary before use.

11.0 Analytical Procedures[Reserved]

12.0 Data Analyses and Calculations[Reserved]

13.0 Method Performance[Reserved]

14.0 Pollution Prevention[Reserved]

15.0 Waste Management[Reserved]

16.0 References

1. Dubose, D.A., and G.E. Harris. Response Factors of VOC Analyzers at a Meter Reading of 10,000 ppmv for Selected Organic Compounds. U.S. Environmental Protection Agency, Research Triangle Park, NC. Publication No. EPA 600/2-81051. September 1981.
2. Brown, G.E., *et al.* Response Factors of VOC Analyzers Calibrated with Methane for Selected Organic Compounds. U.S. Environmental Protection Agency, Research Triangle Park, NC. Publication No. EPA 600/2-81-022. May 1981.
3. DuBose, D.A. *et al.* Response of Portable VOC Analyzers to Chemical Mixtures. U.S. Environmental Protection Agency, Research Triangle Park, NC. Publication No. EPA 600/2-81-110. September 1981.
4. Handbook of Hazardous Materials: Fire, Safety, Health. Alliance of American Insurers. Schaumburg, IL. 1983.

17.0 Tables, Diagrams, Flowcharts, and Validation Data[Reserved]

5.2 Transportation And Marketing Of Petroleum Liquids¹⁻³

5.2.1 General

The transportation and marketing of petroleum liquids involve many distinct operations, each of which represents a potential source of evaporation loss. Crude oil is transported from production operations to a refinery by tankers, barges, rail tank cars, tank trucks, and pipelines. Refined petroleum products are conveyed to fuel marketing terminals and petrochemical industries by these same modes. From the fuel marketing terminals, the fuels are delivered by tank trucks to service stations, commercial accounts, and local bulk storage plants. The final destination for gasoline is usually a motor vehicle gasoline tank. Similar distribution paths exist for fuel oils and other petroleum products. A general depiction of these activities is shown in Figure 5.2-1.

5.2.2 Emissions And Controls

Evaporative emissions from the transportation and marketing of petroleum liquids may be considered, by storage equipment and mode of transportation used, in four categories:

1. Rail tank cars, tank trucks, and marine vessels: loading, transit, and ballasting losses.
2. Service stations: bulk fuel drop losses and underground tank breathing losses.
3. Motor vehicle tanks: refueling losses.
4. Large storage tanks: breathing, working, and standing storage losses. (See Chapter 7, "Liquid Storage Tanks".)

Evaporative and exhaust emissions are also associated with motor vehicle operation, and these topics are discussed in AP-42 *Volume II: Mobile Sources*.

5.2.2.1 Rail Tank Cars, Tank Trucks, And Marine Vessels -

Emissions from these sources are from loading losses, ballasting losses, and transit losses.

5.2.2.1.1 Loading Losses -

Loading losses are the primary source of evaporative emissions from rail tank car, tank truck, and marine vessel operations. Loading losses occur as organic vapors in "empty" cargo tanks are displaced to the atmosphere by the liquid being loaded into the tanks. These vapors are a composite of (1) vapors formed in the empty tank by evaporation of residual product from previous loads, (2) vapors transferred to the tank in vapor balance systems as product is being unloaded, and (3) vapors generated in the tank as the new product is being loaded. The quantity of evaporative losses from loading operations is, therefore, a function of the following parameters:

- Physical and chemical characteristics of the previous cargo;
- Method of unloading the previous cargo;
- Operations to transport the empty carrier to a loading terminal;
- Method of loading the new cargo; and
- Physical and chemical characteristics of the new cargo.

The principal methods of cargo carrier loading are illustrated in Figure 5.2-2, Figure 5.2-3, and Figure 5.2-4. In the splash loading method, the fill pipe dispensing the cargo is lowered only part way into the cargo tank. Significant turbulence and vapor/liquid contact occur during the splash

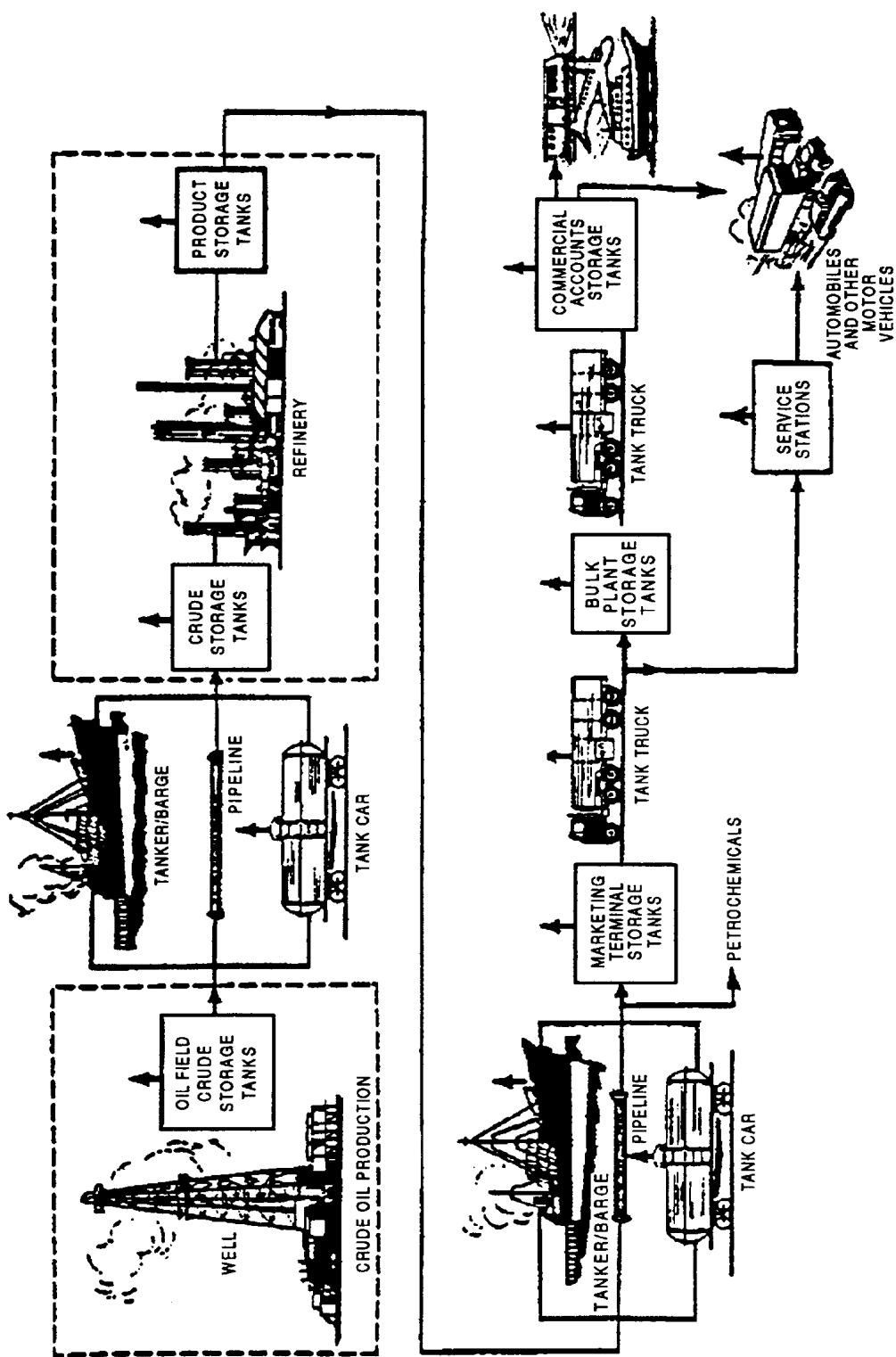


Figure 5.2-1. Flow sheet of petroleum production, refining, and distribution systems. (Points of organic emissions are indicated by vertical arrows.)

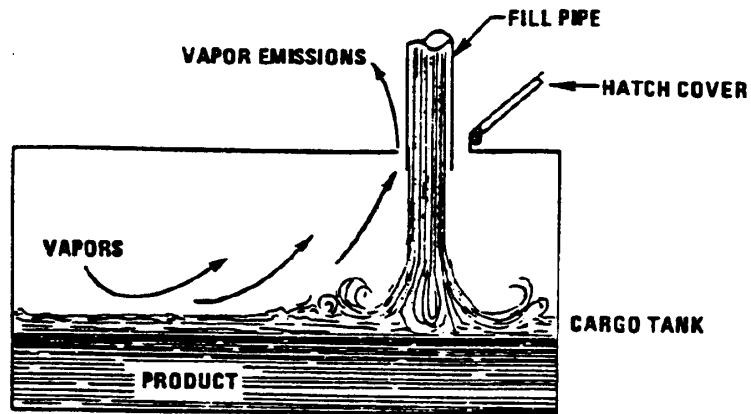


Figure 5.2-2. Splash loading method.

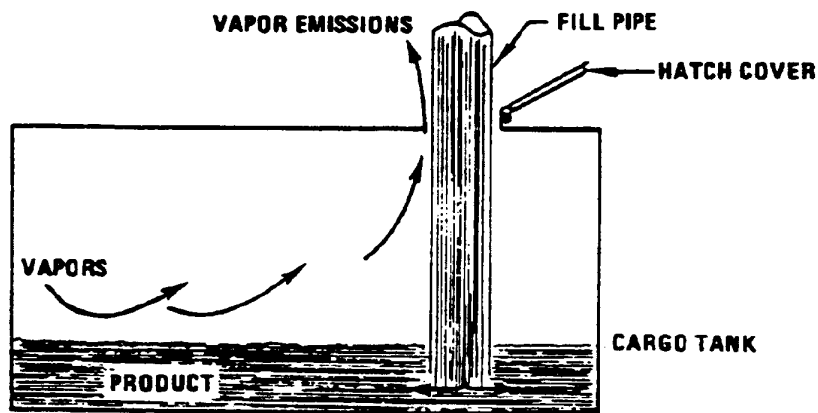


Figure 5.2-3. Submerged fill pipe.

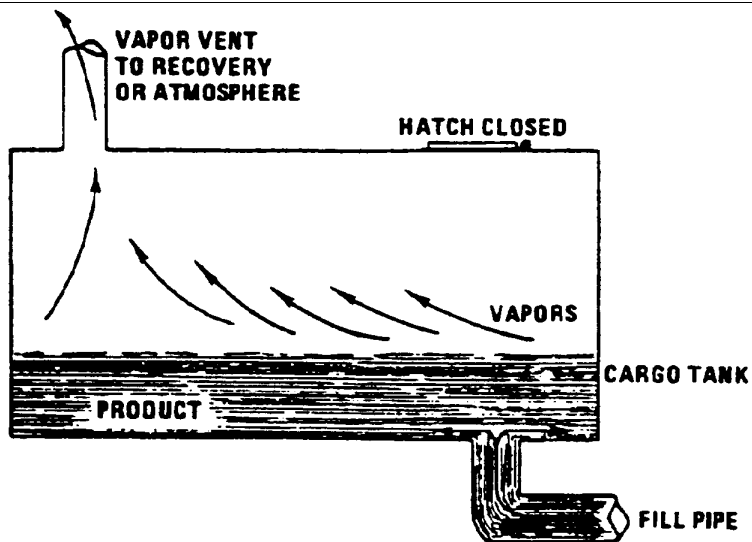


Figure 5.2-4. Bottom loading.

loading operation, resulting in high levels of vapor generation and loss. If the turbulence is great enough, liquid droplets will be entrained in the vented vapors.

A second method of loading is submerged loading. Two types are the submerged fill pipe method and the bottom loading method. In the submerged fill pipe method, the fill pipe extends almost to the bottom of the cargo tank. In the bottom loading method, a permanent fill pipe is attached to the cargo tank bottom. During most of submerged loading by both methods, the fill pipe opening is below the liquid surface level. Liquid turbulence is controlled significantly during submerged loading, resulting in much lower vapor generation than encountered during splash loading.

The recent loading history of a cargo carrier is just as important a factor in loading losses as the method of loading. If the carrier has carried a nonvolatile liquid such as fuel oil, or has just been cleaned, it will contain vapor-free air. If it has just carried gasoline and has not been vented, the air in the carrier tank will contain volatile organic vapors, which will be expelled during the loading operation along with newly generated vapors.

Cargo carriers are sometimes designated to transport only one product, and in such cases are practicing "dedicated service". Dedicated gasoline cargo tanks return to a loading terminal containing air fully or partially saturated with vapor from the previous load. Cargo tanks may also be "switch loaded" with various products, so that a nonvolatile product being loaded may expel the vapors remaining from a previous load of a volatile product such as gasoline. These circumstances vary with the type of cargo tank and with the ownership of the carrier, the petroleum liquids being transported, geographic location, and season of the year.

One control measure for vapors displaced during liquid loading is called "vapor balance service", in which the cargo tank retrieves the vapors displaced during product unloading at bulk plants or service stations and transports the vapors back to the loading terminal. Figure 5.2-5 shows a tank truck in vapor balance service filling a service station underground tank and taking on displaced gasoline vapors for return to the terminal. A cargo tank returning to a bulk terminal in vapor balance service normally is saturated with organic vapors, and the presence of these vapors at the start of submerged loading of the tanker truck results in greater loading losses than encountered during nonvapor balance, or "normal", service. Vapor balance service is usually not practiced with marine vessels, although some vessels practice emission control by means of vapor transfer within their own cargo tanks during ballasting operations, discussed below.

Emissions from loading petroleum liquid can be estimated (with a probable error of ± 30 percent)⁴ using the following expression:

$$L_L = 12.46 \frac{SPM}{T} \quad (1)$$

where:

L_L = loading loss, pounds per 1000 gallons ($\text{lb}/10^3 \text{ gal}$) of liquid loaded

S = a saturation factor (see Table 5.2-1)

P = true vapor pressure of liquid loaded, pounds per square inch absolute (psia)
(see Section 7.1, "Organic Liquid Storage Tanks")

M = molecular weight of vapors, pounds per pound-mole ($\text{lb}/\text{lb-mole}$) (see Section 7.1, "Organic Liquid Storage Tanks")

T = temperature of bulk liquid loaded, $^{\circ}\text{R}$ ($^{\circ}\text{F} + 460$)

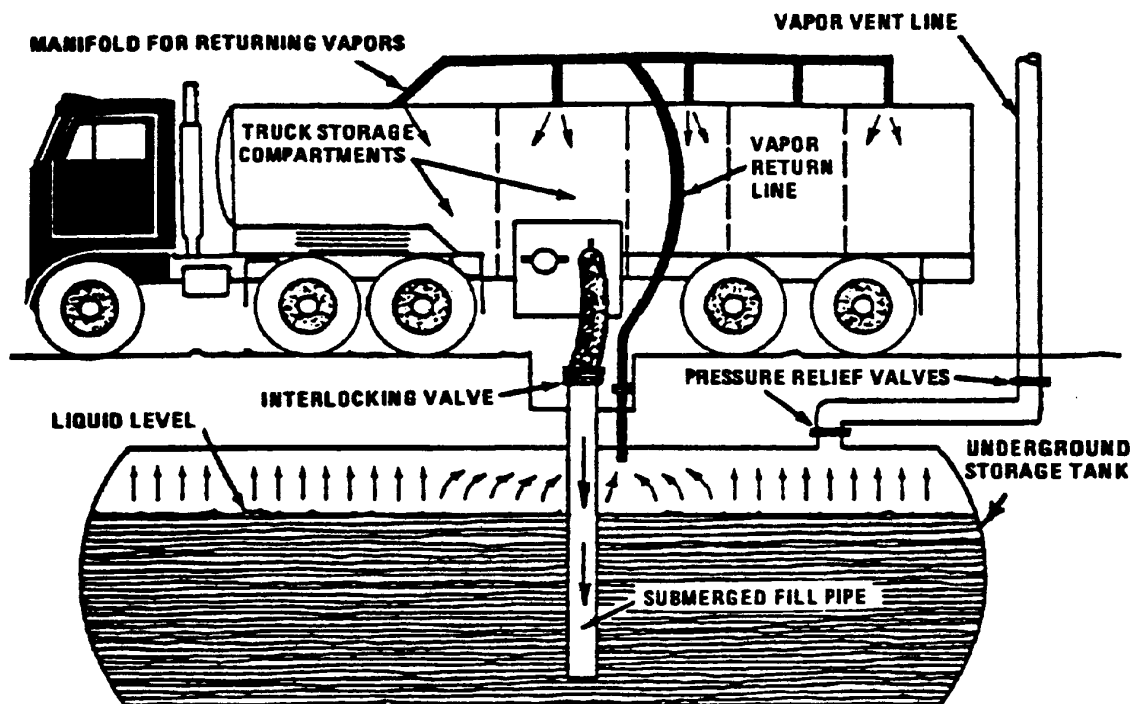


Figure 5.2-5. Tank truck unloading into a service station underground storage tank and practicing "vapor balance" form of emission control.

Table 5.2-1. SATURATION (S) FACTORS FOR CALCULATING PETROLEUM LIQUID LOADING LOSSES

Cargo Carrier	Mode Of Operation	S Factor
Tank trucks and rail tank cars	Submerged loading of a clean cargo tank	0.50
	Submerged loading: dedicated normal service	0.60
	Submerged loading: dedicated vapor balance service	1.00
	Splash loading of a clean cargo tank	1.45
	Splash loading: dedicated normal service	1.45
	Splash loading: dedicated vapor balance service	1.00
Marine vessels ^a	Submerged loading: ships	0.2
	Submerged loading: barges	0.5

^a For products other than gasoline and crude oil. For marine loading of gasoline, use factors from Table 5.2-2. For marine loading of crude oil, use Equations 2 and 3 and Table 5.2-3.

The saturation factor, S , represents the expelled vapor's fractional approach to saturation, and it accounts for the variations observed in emission rates from the different unloading and loading methods. Table 5.2-1 lists suggested saturation factors.

Emissions from controlled loading operations can be calculated by multiplying the uncontrolled emission rate calculated in Equation 1 by an overall reduction efficiency term:

$$\left(1 - \frac{\text{eff}}{100} \right)$$

The overall reduction efficiency should account for the capture efficiency of the collection system as well as both the control efficiency and any downtime of the control device. Measures to reduce loading emissions include selection of alternate loading methods and application of vapor recovery equipment. The latter captures organic vapors displaced during loading operations and recovers the vapors by the use of refrigeration, absorption, adsorption, and/or compression. The recovered product is piped back to storage. Vapors can also be controlled through combustion in a thermal oxidation unit, with no product recovery. Figure 5.2-6 demonstrates the recovery of gasoline vapors from tank trucks during loading operations at bulk terminals. Control efficiencies for the recovery units range from 90 to over 99 percent, depending on both the nature of the vapors and the type of control equipment used.⁵⁻⁶ However, not all of the displaced vapors reach the control device, because of leakage from both the tank truck and collection system. The collection efficiency should be assumed to be 99.2 percent for tanker trucks passing the MACT-level annual leak test (not more than 1 inch water column pressure change in 5 minutes after pressurizing to 18 inches water followed by pulling a vacuum of 6 inches water).⁷ A collection efficiency of 98.7 percent (a 1.3 percent leakage rate) should be assumed for trucks passing the NSPS-level annual test (3 inches pressure change). A collection efficiency of 70 percent should be assumed for trucks not passing one of these annual leak tests.⁶

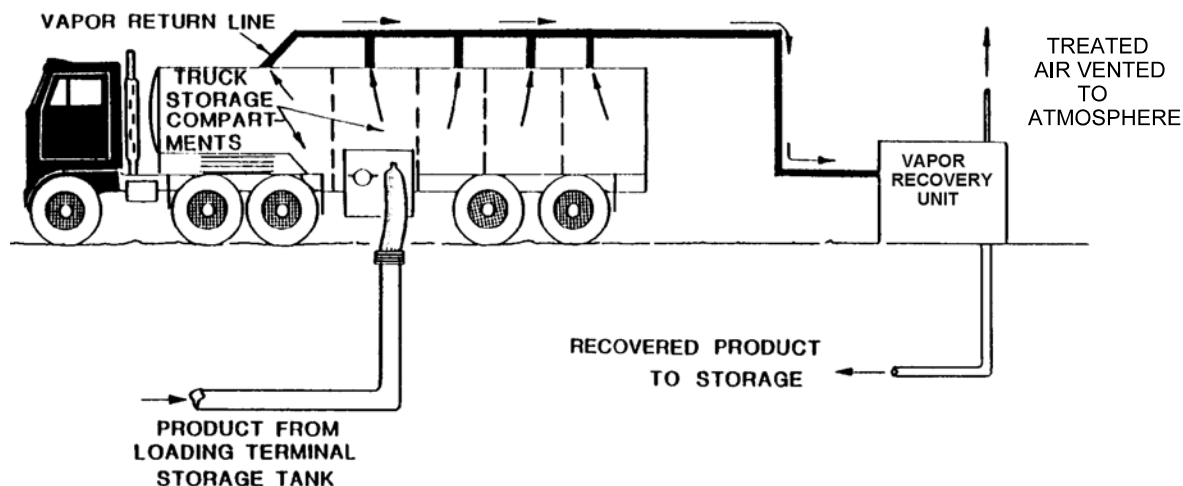


Figure 5.2-6. Tank truck loading with vapor recovery.

Sample Calculation -

Loading losses (L_L) from a gasoline tank truck in dedicated vapor balance service and practicing vapor recovery would be calculated as follows, using Equation 1:

Design basis -

Cargo tank volume is 8000 gal
Gasoline Reid vapor pressure (RVP) is 9 psia
Product temperature is 80°F
Vapor recovery efficiency is 95 percent
Vapor collection efficiency is 98.7 percent (NSPS-level annual leak test)

Loading loss equation -

$$L_L = 12.46 \frac{\text{SPM}}{T} \left(1 - \frac{\text{eff}}{100} \right)$$

where:

S = saturation factor (see Table 5.2-1) - 1.00
P = true vapor pressure of gasoline = 6.6 psia
M = molecular weight of gasoline vapors = 66
T = temperature of gasoline = 540°R
eff = overall reduction efficiency (95 percent control x 98.7 percent collection) = 94 percent

$$\begin{aligned} L_L &= 12.46 \frac{(1.00)(6.6)(66)}{540} \left(1 - \frac{94}{100} \right) \\ &= 0.60 \text{ lb}/10^3 \text{ gal} \end{aligned}$$

Total loading losses are:

$$(0.60 \text{ lb}/10^3 \text{ gal})(8.0 \times 10^3 \text{ gal}) = 4.8 \text{ pounds (lb)}$$

Measurements of gasoline loading losses from ships and barges have led to the development of emission factors for these specific loading operations.⁸ These factors are presented in Table 5.2-2 and should be used instead of Equation 1 for gasoline loading operations at marine terminals. Factors are expressed in units of milligrams per liter (mg/L) and pounds per 1000 gallons (lb/10³ gal).

Table 5.2-2 (Metric And English Units). VOLATILE ORGANIC COMPOUND (VOC) EMISSION FACTORS FOR GASOLINE LOADING OPERATIONS AT MARINE TERMINALS^a

Vessel Tank Condition	Previous Cargo	Ships/Ocean Barges ^b		Barges ^b	
		mg/L Transferred	lb/10 ³ gal Transferred	mg/L Transferred	lb/10 ³ gal Transferred
Uncleaned	Volatile ^c	315	2.6	465	3.9
Ballasted	Volatile	205	1.7	— ^d	— ^d
Cleaned	Volatile	180	1.5	ND	ND
Gas-freed	Volatile	85	0.7	ND	ND
Any condition	Nonvolatile	85	0.7	ND	ND
Gas-freed	Any cargo	ND	ND	245	2.0
Typical overall situation ^e	Any cargo	215	1.8	410	3.4

^a References 2,9. Factors are for both VOC emissions (which excludes methane and ethane) and total organic emissions, because methane and ethane have been found to constitute a negligible weight fraction of the evaporative emissions from gasoline. ND = no data.

^b Ocean barges (tank compartment depth about 12.2 m [40 ft]) exhibit emission levels similar to tank ships. Shallow draft barges (compartment depth 3.0 to 3.7 m [10 to 12 ft]) exhibit higher emission levels.

^c Volatile cargoes are those with a true vapor pressure greater than 10 kilopascals (kPa) (1.5 psia).

^d Barges are usually not ballasted.

^e Based on observation that 41% of tested ship compartments were uncleaned, 11% ballasted, 24% cleaned, and 24% gas-freed. For barges, 76% were uncleaned.

In addition to Equation 1, which estimates emissions from the loading of petroleum liquids, Equation 2 has been developed specifically for estimating emissions from the loading of crude oil into ships and ocean barges:

$$C_L = C_A + C_G \quad (2)$$

where:

C_L = total loading loss, lb/10³ gal of crude oil loaded

C_A = arrival emission factor, contributed by vapors in the empty tank compartment before loading, lb/10³ gal loaded (see Note below)

C_G = generated emission factor, contributed by evaporation during loading, lb/10³ gal loaded

Note: Values of C_A for various cargo tank conditions are listed in Table 5.2-3.

5.2-3 (English Units). AVERAGE ARRIVAL EMISSION FACTORS, C_A , FOR CRUDE OIL LOADING EMISSION EQUATION^a

Ship/Ocean Barge Tank Condition	Previous Cargo	Arrival Emission Factor, lb/10 ³ gal
Uncleaned	Volatile ^b	0.86
Ballasted	Volatile	0.46
Cleaned or gas-freed	Volatile	0.33
Any condition	Nonvolatile	0.33

^a Arrival emission factors (C_A) to be added to generated emission factors (C_G) calculated in Equation 3 to produce total crude oil loading loss (C_L). Factors are for total organic compounds; VOC emission factors average about 15% lower, because VOC does not include methane or ethane.

^b Volatile cargoes are those with a true vapor pressure greater than 10 kPa (1.5 psia).

This equation was developed empirically from test measurements of several vessel compartments.⁸ The quantity C_G can be calculated using Equation 3:

$$C_G = 1.84 (0.44 P - 0.42) \frac{M G}{T} \quad (3)$$

where:

P = true vapor pressure of loaded crude oil, psia
M = molecular weight of vapors, lb/lb-mole
G = vapor growth factor = 1.02 (dimensionless)
T = temperature of vapors, °R (°F + 460)

Emission factors derived from Equation 3 and Table 5.2-3 represent total organic compounds. Volatile organic compound (VOC) emission factors (which exclude methane and ethane because they are exempted from the regulatory definition of "VOC") for crude oil vapors have been found to range from approximately 55 to 100 weight percent of these total organic factors. When specific vapor composition information is not available, the VOC emission factor can be estimated by taking 85 percent of the total organic factor.³

5.2.2.1.2 Ballasting Losses -

Ballasting operations are a major source of evaporative emissions associated with the unloading of petroleum liquids at marine terminals. It is common practice to load several cargo tank compartments with sea water after the cargo has been unloaded. This water, termed "ballast", improves the stability of the empty tanker during the subsequent voyage. Although ballasting practices vary, individual cargo tanks are ballasted typically about 80 percent, and the total vessel 15 to 40 percent, of capacity. Ballasting emissions occur as vapor-laden air in the "empty" cargo tank is displaced to the atmosphere by ballast water being pumped into the tank. Upon arrival at a loading port, the ballast water is pumped from the cargo tanks before the new cargo is loaded. The ballasting of cargo tanks reduces the quantity of vapors returning in the empty tank, thereby reducing the quantity of vapors emitted during subsequent tanker loading. Regulations administered by the U. S. Coast Guard require that, at marine terminals located in ozone nonattainment areas, large tankers with crude oil washing systems contain the organic vapors from ballasting.¹⁰ This is accomplished principally by displacing the vapors during ballasting into a cargo tank being simultaneously unloaded. In other areas, marine vessels emit organic vapors directly to the atmosphere.

Equation 4 has been developed from test data to calculate the ballasting emissions from crude oil ships and ocean barges⁸:

$$L_B = 0.31 + 0.20 P + 0.01 P U_A \quad (4)$$

where:

- L_B = ballasting emission factor, lb/10³ gal of ballast water
 P = true vapor pressure of discharged crude oil, psia
 U_A = arrival cargo true ullage, before dockside discharge, measured from the deck, feet;
 (the term "ullage" here refers to the distance between the cargo surface level and the deck level)

Table 5.2-4 lists average total organic emission factors for ballasting into uncleaned crude oil cargo compartments. The first category applies to "full" compartments wherein the crude oil true ullage just before cargo discharge is less than 1.5 meters (m) (5 ft). The second category applies to lightered, or short-loaded, compartments (part of cargo previously discharged, or original load a partial fill), with an arrival true ullage greater than 1.5 m (5 ft). It should be remembered that these tabulated emission factors are examples only, based on average conditions, to be used when crude oil vapor pressure is unknown. Equation 4 should be used when information about crude oil vapor pressure and cargo compartment condition is available. The following sample calculation illustrates the use of Equation 4.

5.2-4 (Metric And English Units). TOTAL ORGANIC EMISSION FACTORS
FOR CRUDE OIL BALLASTING^a

Compartment Condition Before Cargo Discharge	Average Emission Factors			
	By Category		Typical Overall ^b	
	mg/L Ballast Water	lb/10 ³ gal Ballast Water	mg/L Ballast Water	lb/10 ³ gal Ballast Water
Fully loaded ^c	111	0.9	129	1.1
Lightered or previously short loaded ^d	171	1.4		

^a Assumes crude oil temperature of 16°C (60°F) and RVP of 34 kPa (5 psia). VOC emission factors average about 85% of these total organic factors, because VOCs do not include methane or ethane.

^b Based on observation that 70% of tested compartments had been fully loaded before ballasting. May not represent average vessel practices.

^c Assumed typical arrival ullage of 0.6 m (2 ft).

^d Assumed typical arrival ullage of 6.1 m (20 ft).

Sample Calculation -

Ballasting emissions from a crude oil cargo ship would be calculated as follows, using Equation 4:

Design basis -

Vessel and cargo description: 80,000 dead-weight-ton tanker, crude oil capacity 500,000 barrels (bbl); 20 percent of the cargo capacity is filled with ballast water after cargo discharge. The crude oil has an RVP of 6 psia and is discharged at 75°F.

Compartment conditions: 70 percent of the ballast water is loaded into compartments that had been fully loaded to 2 ft ullage, and 30 percent is loaded into compartments that had been lightered to 15 ft ullage before arrival at dockside.

Ballasting emission equation -

$$L_B = 0.31 + 0.20 P + 0.01 P U_A$$

where:

P = true vapor pressure of crude oil
= 4.6 psia

U_A = true cargo ullage for the full compartments = 2 ft, and true cargo ullage for the lightered compartments = 15 ft

$$\begin{aligned} L_B &= 0.70 [0.31 + (0.20) (4.6) + (0.01) (4.6) (2)] \\ &\quad + 0.30 [0.31 + (0.20) (4.6) + (0.01) (4.6) (15)] \\ &= 1.5 \text{ lb}/10^3 \text{ gal} \end{aligned}$$

Total ballasting emissions are:

$$(1.5 \text{ lb}/10^3 \text{ gal}) (0.20) (500,000 \text{ bbl}) (42 \text{ gal/bbl}) = 6,300 \text{ lb}$$

Since VOC emissions average about 85 percent of these total organic emissions, emissions of VOCs are about: $(0.85)(6,300 \text{ lb}) = 5,360 \text{ lb}$

5.2.2.1.3 Transit Losses -

In addition to loading and ballasting losses, losses occur while the cargo is in transit. Transit losses are similar in many ways to breathing losses associated with petroleum storage (see Section 7.1, "Organic Liquid Storage Tanks"). Experimental tests on ships and barges⁴ have indicated that transit losses can be calculated using Equation 5:

$$L_T = 0.1 P W \tag{5}$$

where:

L_T = transit loss from ships and barges, lb/week-10³ gal transported
 P = true vapor pressure of the transported liquid, psia
 W = density of the condensed vapors, lb/gal

Emissions from gasoline truck cargo tanks during transit have been studied by a combination of theoretical and experimental techniques, and typical emission values are presented in Table 5.2-5.¹¹⁻¹² Emissions depend on the extent of venting from the cargo tank during transit, which in turn depends on the vapor tightness of the tank, the pressure relief valve settings, the pressure in the tank at the start of the trip, the vapor pressure of the fuel being transported, and the degree of fuel vapor saturation of the space in the tank. The emissions are not directly proportional to the time spent in transit. If the vapor leakage rate of the tank increases, emissions increase up to a point, and then the rate changes as other determining factors take over. Truck tanks in dedicated vapor balance service usually contain saturated vapors, and this leads to lower emissions during transit because no additional fuel evaporates to raise the pressure in the tank to cause venting. Table 5.2-5 lists "typical" values for transit emissions and "extreme" values that could occur in the unlikely event that all determining factors combined to cause maximum emissions.

Table 5.2-5 (Metric And English Units). TOTAL UNCONTROLLED ORGANIC EMISSION FACTORS FOR PETROLEUM LIQUID RAIL TANK CARS AND TANK TRUCKS

Emission Source	Gasoline ^a	Crude Oil ^b	Jet Naphtha (JP-4)	Jet Kerosene	Distillate Oil No. 2	Residual Oil No. 6
Loading operations ^c						
Submerged loading - Dedicated normal service ^d						
mg/L transferred	590	240	180	1.9	1.7	0.01
lb/10 ³ gal transferred	5	2	1.5	0.016	0.014	0.0001
Submerged loading - Vapor balance service ^d						
mg/L transferred	980	400	300	— ^e	— ^e	— ^e
lb/10 ³ gal transferred	8	3	2.5	— ^e	— ^e	— ^e
Splash loading - Dedicated normal service						
mg/L transferred	1,430	580	430	5	4	0.03
lb/10 ³ gal transferred	12	5	4	0.04	0.03	0.0003
Splash loading - Vapor balance service						
mg/L transferred	980	400	300	— ^e	— ^e	— ^e
lb/10 ³ gal transferred	8	3	2.5	— ^e	— ^e	— ^e

Table 5.2-5 (cont.).

Emission Source	Gasoline ^a	Crude Oil ^b	Jet Naphtha (JP-4)	Jet Kerosene	Distillate Oil No. 2	Residual Oil No. 6
Transit losses						
Loaded with product						
mg/L transported						
Typical	0 - 1.0	ND	ND	ND	ND	ND
Extreme	0 - 9.0	ND	ND	ND	ND	ND
lb/10 ³ gal transported						
Typical	0 - 0.01	ND	ND	ND	ND	ND
Extreme	0 - 0.08	ND	ND	ND	ND	ND
Return with vapor						
mg/L transported						
Typical	0 - 13.0	ND	ND	ND	ND	ND
Extreme	0 - 44.0	ND	ND	ND	ND	ND
lb/10 ³ gal transported						
Typical	0 - 0.11	ND	ND	ND	ND	ND
Extreme	0 - 0.37	ND	ND	ND	ND	ND

^a Reference 2. Gasoline factors represent emissions of VOC as well as total organics, because methane and ethane constitute a negligible weight fraction of the evaporative emissions from gasoline. VOC factors for crude oil can be assumed to be 15% lower than the total organic factors, to account for the methane and ethane content of crude oil evaporative emissions. All other products should be assumed to have VOC factors equal to total organics. The example gasoline has an RVP of 69 kPa (10 psia). ND = no data.

^b The example crude oil has an RVP of 34 kPa (5 psia).

^c Loading emission factors are calculated using Equation 1 for a dispensed product temperature of 16°C (60°F).

^d Reference 2.

^e Not normally used.

In the absence of specific inputs for Equations 1 through 5, the typical evaporative emission factors presented in Tables 5.2-5 and 5.2-6 should be used. It should be noted that, although the crude oil used to calculate the emission values presented in these tables has an RVP of 5, the RVP of crude oils can range from less than 1 up to 10. Similarly, the RVP of gasolines ranges from 7 to 13. In areas where loading and transportation sources are major factors affecting air quality, it is advisable to obtain the necessary parameters and to calculate emission estimates using Equations 1 through 5.

5.2.2.2 Service Stations -

Another major source of evaporative emissions is the filling of underground gasoline storage tanks at service stations. Gasoline is usually delivered to service stations in 30,000-liter (8,000-gal) tank trucks or smaller account trucks. Emissions are generated when gasoline vapors in the underground storage tank are displaced to the atmosphere by the gasoline being loaded into the tank. As with other loading losses, the quantity of loss in service station tank filling depends on several variables, including the method and rate of filling, the tank configuration, and the gasoline temperature, vapor pressure and composition. An average emission rate for submerged filling is 880 mg/L (7.3 lb/1000 gal) of transferred gasoline, and the rate for splash filling is 1380 mg/L (11.5 lb/1000 gal) transferred gasoline (see Table 5.2-7).⁵

Table 5.2-6 (Metric And English Units). TOTAL ORGANIC EMISSION FACTORS
FOR PETROLEUM MARINE VESSEL SOURCES^a

Emission Source	Gasoline ^b	Crude Oil ^c	Jet Naphtha (JP-4)	Jet Kerosene	Distillate Oil No. 2	Residual Oil No. 6
Loading operations						
Ships/ocean barges						
mg/L transferred	— ^d	73	60	0.63	0.55	0.004
lb/10 ³ gal transferred	— ^d	0.61	0.50	0.005	0.005	0.00004
Barges						
mg/L transferred	— ^d	120	150	1.60	1.40	0.011
lb/10 ³ gal transferred	— ^d	1.0	1.2	0.013	0.012	0.00009
Tanker ballasting						
mg/L ballast water	100	— ^e	ND	ND	ND	ND
lb/10 ³ gal ballast water	0.8	— ^e	ND	ND	ND	ND
Transit						
mg/week-L transported	320	150	84	0.60	0.54	0.003
lb/week-10 ³ gal transported	2.7	1.3	0.7	0.005	0.005	0.00003

^a Factors are for a dispensed product of 16°C (60°F). ND = no data.

^b Factors represent VOC as well as total organic emissions, because methane and ethane constitute a negligible fraction of gasoline evaporative emissions. All products other than crude oil can be assumed to have VOC factors equal to total organic factors. The example gasoline has an RVP of 69 kPa (10 psia).

^c VOC emission factors for a typical crude oil are 15% lower than the total organic factors shown, in order to account for methane and ethane. The example crude oil has an RVP of 34 kPa (5 psia).

^d See Table 5.2-2 for these factors.

^e See Table 5.2-4 for these factors.

Emissions from underground tank filling operations at service stations can be reduced by the use of a vapor balance system such as in Figure 5.2-5 (termed Stage I vapor control). The vapor balance system employs a hose that returns gasoline vapors displaced from the underground tank to the tank truck cargo compartments being emptied. The control efficiency of the balance system ranges from 93 to 100 percent. Organic emissions from underground tank filling operations at a service station employing a vapor balance system and submerged filling are not expected to exceed 40 mg/L (0.3 lb/1000 gal) of transferred gasoline.

Table 5.2-7 (Metric And English Units). EVAPORATIVE EMISSIONS FROM GASOLINE SERVICE STATION OPERATIONS^a

Emission Source	Emission Rate	
	mg/L Throughput	lb/10 ³ gal Throughput
Filling underground tank (Stage I)		
Submerged filling	880	7.3
Splash filling	1,380	11.5
Balanced submerged filling	40	0.3
Underground tank breathing and emptying ^b	120	1.0
Vehicle refueling operations (Stage II)		
Displacement losses (uncontrolled) ^c	1,320	11.0
Displacement losses (controlled)	132	1.1
Spillage	80	0.7

^a Factors are for VOC as well as total organic emissions, because of the methane and ethane content of gasoline evaporative emissions is negligible.

^b Includes any vapor loss between underground tank and gas pump.

^c Based on Equation 6, using average conditions.

A second source of vapor emissions from service stations is underground tank breathing. Breathing losses occur daily and are attributable to gasoline evaporation and barometric pressure changes. The frequency with which gasoline is withdrawn from the tank, allowing fresh air to enter to enhance evaporation, also has a major effect on the quantity of these emissions. An average breathing emission rate is 120 mg/L (1.0 lb/1000 gal) of throughput.

5.2.2.3 Motor Vehicle Refueling -

Service station vehicle refueling activity also produces evaporative emissions. Vehicle refueling emissions come from vapors displaced from the automobile tank by dispensed gasoline and from spillage. The quantity of displaced vapors depends on gasoline temperature, auto tank temperature, gasoline RVP, and dispensing rate. Equation 6 can be used to estimate uncontrolled displacement losses from vehicle refueling for a particular set of conditions.¹⁴

$$E_R = 264.2 [(-5.909) - 0.0949 (\Delta T) + 0.0884 (T_D) + 0.485 (RVP)] \quad (6)$$

where:

E_R = refueling emissions, mg/L
 ΔT = difference between temperature of fuel in vehicle tank and temperature of dispensed fuel, °F
 T_D = temperature of dispensed fuel, °F
RVP = Reid vapor pressure, psia

Note that this equation and the spillage loss factor are incorporated into the *MOBILE* model. The *MOBILE* model allows for disabling of this calculation if it is desired to include these emissions in the stationary area source portion of an inventory rather than in the mobile source portion. It is estimated that the uncontrolled emissions from vapors displaced during vehicle refueling average 1320 mg/L (11.0 lb/1000 gal) of dispensed gasoline.^{5,13}

Spillage loss is made up of contributions from prefill and postfill nozzle drip and from spit-back and

overflow from the vehicles's fuel tank filler pipe during filling. The amount of spillage loss can depend on several variables, including service station business characteristics, tank configuration, and operator techniques. An average spillage loss is 80 mg/L (0.7 lb/1000 gal) of dispensed gasoline.^{5,13}

Control methods for vehicle refueling emissions are based on conveying the vapors displaced from the vehicle fuel tank to the underground storage tank vapor space through the use of a special hose and nozzle, as depicted in Figure 5.2-7 (termed Stage II vapor control). In "balance" vapor control systems, the vapors are conveyed by natural pressure differentials established during refueling. In "vacuum assist" systems, the conveyance of vapors from the auto fuel tank to the underground storage tank is assisted by a vacuum pump. Tests on a few systems have indicated overall systems control efficiencies in the range of 88 to 92 percent.^{5,13} When inventorying these emissions as an area source, rule penetration and rule effectiveness should also be taken into account. *Procedures For Emission Inventory Preparation, Volume IV: Mobile Sources*, EPA-450/4-81-026d, provides more detail on this.

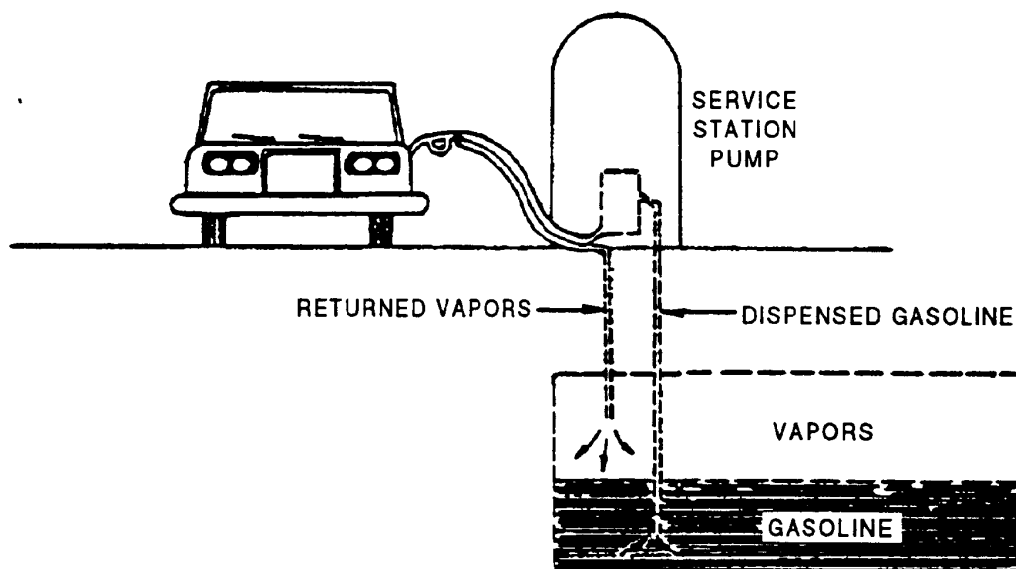


Figure 5.2-7. Automobile refueling vapor recovery system.

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Options for Removing Accumulated Fluid and Improving Flow in Gas Wells



Executive Summary

When first completed, many natural gas wells have sufficient reservoir pressure to flow formation fluids (water and liquid hydrocarbon) to the surface along with the produced gas. As gas production continues, the reservoir pressure declines, and as pressure declines, the velocity of the fluid in the well tubing decreases. Eventually, the gas velocity up the production tubing is no longer sufficient to lift liquid droplets to the surface. Liquids accumulate in the tubing, creating additional pressure drop, slowing gas velocity, and raising pressure in the reservoir surrounding the well perforations and inside the casing. As the bottom well pressure approaches reservoir shut-in pressure, gas flow stops and all liquids accumulate at the bottom of the tubing. A common approach to temporarily restore flow is to vent the well to the atmosphere (well “blowdown”), which produces substantial methane emissions. The *U.S. Inventory of Greenhouse Gas Emissions and Sinks 1990–2008* estimates 9.6 billion cubic feet (Bcf) of annual methane emissions from venting of low pressure gas wells.

At different stages in the life of a gas well, various alternatives to repeated well venting can be deployed to move accumulated liquids to the surface. These options include:

- ★ Foaming agents or surfactants
- ★ Velocity tubing
- ★ Plunger lift, operated manually or with ‘smart’ well automation
- ★ Downhole pumps, which include reciprocating (beam) pumps and rotating (progressive cavity) pumps.

Natural Gas STAR Partners report significant methane emission reductions and economic benefits from implementing one or more lift options to remove accumulated liquids in gas wells. Not only are vented methane emissions reduced or eliminated, but these lift techniques can provide the additional benefit of increased gas production.

Economic and Environmental Benefits

Method for Reducing Natural Gas Losses	Volume of Natural Gas Savings and Incremental Production ¹ (Mcf/well/year)	Value of Natural Gas Savings and Additional Production (Mcf/well/year)			Implementation Cost ¹ (2010 \$/Well)	Project Payback (years)		
		\$3 per Mcf	\$5 per Mcf	\$7 per Mcf		\$3 per Mcf	\$5 per Mcf	\$7 per Mcf
Use Foaming Agents	500 – 9,360	\$1,500 - \$28,080	\$2,500 - \$46,800	\$3,500 - \$65,520	\$500 - \$9,880	0 to 7	0 to 4	0 to 3
Install Velocity Tubing	9,285 – 27,610	\$27,855 - \$82,830	\$46,425 - \$138,050	\$64,995 - \$193,270	\$7,000 - \$64,000	0 to 3	0 to 2	0 to 1
“Smart” Well Automated Controls for Plunger Lift²	800 – 1,463 ²	\$2,400 - \$4,389	\$4,000 - \$7,315	\$5,600 - \$10,241	\$5,700 - \$18,000	1 to 8	1 to 5	1 to 4
Install Rod Pumps and Pumping Units²	973 – 2,040 ²	\$2,919 - \$6,120	\$4,865 - \$10,200	\$6,811 - \$14,280	\$41,000 - \$62,000	6 to 22	4 to 13	3 to 10

¹Based on results reported by Natural Gas STAR Partners

²Does not include incremental gas production. Includes only potential gas savings from avoided well venting.

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

(Cont'd)

By avoiding or reducing well blowdowns, Partners report annual methane emissions savings that range from 500 thousand cubic feet (Mcf) per well to more than 27,000 Mcf/well. The benefit of increased gas production will vary considerably among individual wells and reservoirs, but can be substantial. For example, Partners report that increased gas production following plunger lift installation yielded as much as 18,250 Mcf per well.

Technology Background

Most gas wells will have liquid loading occur at some point during the productive life of the well. When this occurs, a common course of action to improve gas flow includes:

- ★ Shutting-in the well to allow bottom hole pressure to increase,
- ★ Swabbing the well to remove accumulated fluids,
- ★ Venting the well to the atmosphere (well blowdown),
- ★ Installing an artificial lift system.

'No-Emissions' Solutions for Liquid Loading in Gas Wells:

- ★ Foaming Agents/ Surfactants
 - Low cost/ low volume lift method
 - Applied early in production decline, when the bottom hole pressure still generates sufficient velocity to lift liquid droplets
- ★ Velocity Tubing
 - Low maintenance, effective for low volumes lifted
 - Somewhat expensive to acquire and install
 - Often deployed in combination with foaming agents
- ★ Plunger Lift
 - Long lasting
 - Less expense to install and operate than a pumping unit
 - Often, plunger lift cannot produce a well to its economic limit (abandonment).
 - Challenging to operate effectively; requires more time and expertise to manage.
- ★ Rod Pumping Units
 - Can be deployed in applications to remove greater liquid volumes than plunger lift.

Swabbing and “blowing down” a well to temporarily restore production can vent significant methane emissions, from 80 to 1600 Mcf/year per well. The process must be repeated as fluids reaccumulate, resulting in additional methane emissions. Operators may wait until well blowdown becomes increasingly ineffective before implementing some type of artificial lift. At this point, the cumulative methane emissions from a well could be substantial.

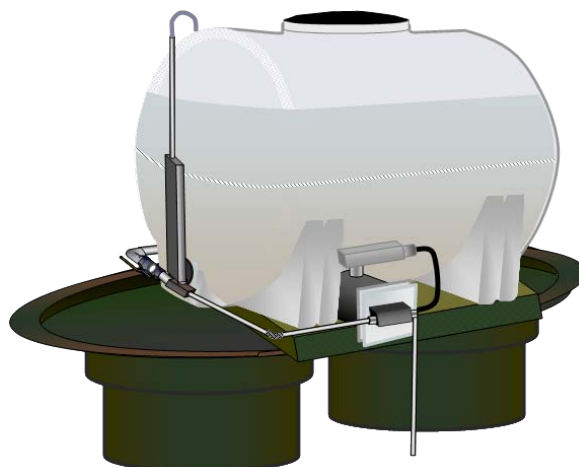
Natural Gas STAR Partners have found that applying artificial lift options early in the life of a well offers significant emissions savings and economic benefits. Each method for lifting liquid in a well has advantages and disadvantages for prolonging the economic life of a well. Total gas savings and methane emission reductions that result from reducing or eliminating well venting will vary for each well depending on flow line operating pressure, reservoir pressure, liquid volume, specific gravity and the number of blowdowns eliminated.

Fluid Removal Options for Gas Wells

Foaming Agents

The use of foam produced by surfactants can be effective for gas wells that accumulate liquid at low rates (Exhibit 1). Foam reduces the density and surface tension of the fluid column, which reduces the critical gas velocity needed to lift fluids to surface and aids liquid removal from the well. Compared to other artificial lift methods, foaming agents are one of the least costly applications for unloading gas wells. Foaming agents work best if the fluid in the well is at least 50 percent water. Surfactants are not

Exhibit 1: Liquid Foaming Agent



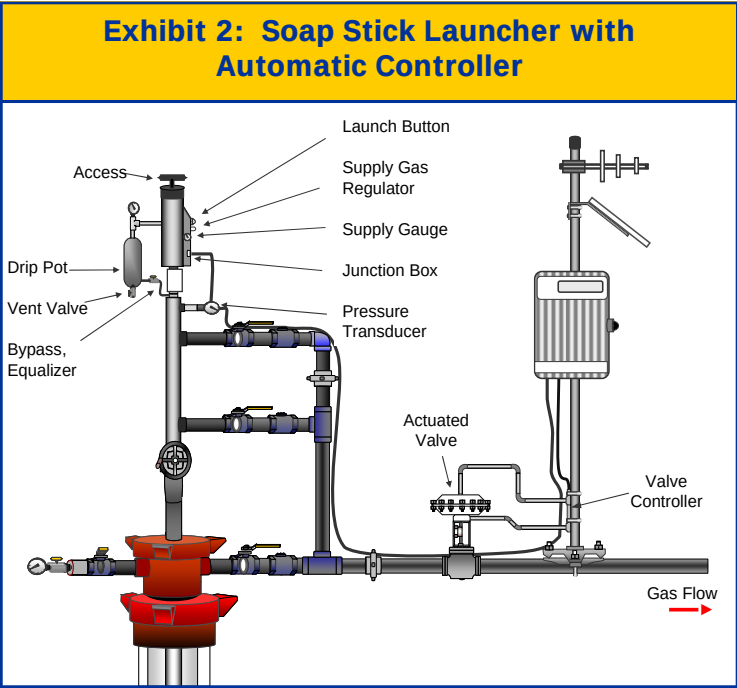
Source: S. Bumgardner, Advanced Resources International, inc.

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

(Cont'd)

effective for natural gas liquids or liquid hydrocarbons.

Surfactants are delivered to the well as soap sticks or as a liquid injected directly into the casing-tubing annulus or down a capillary tubing string. For shallow wells, the surfactant delivery can be as simple as the operator periodically pouring surfactant down the annulus of the well through an open valve. For deep wells, a surfactant injection system requires the installation of surface equipment, as well as regular monitoring. The surface equipment includes a surfactant or 'soap' reservoir, an injection pump, a motor valve with a timer (depending on the installation design), and a power source for the pump (Exhibit 2). No equipment is required in the well, although foaming agents and velocity tubing may be more effective when used in combination.



Source: S. Bumgardner, Advanced Resources International, inc.

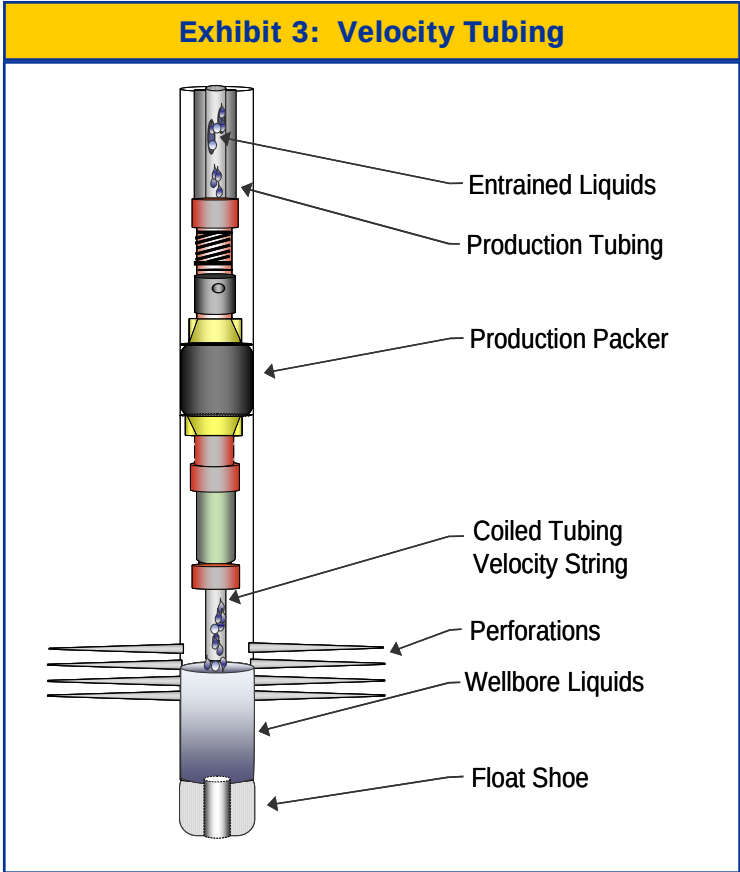
Electric pumps can be powered by AC power where available or by solar power to charge batteries. Other pump choices include mechanical pumps that are actuated by the movement of another piece of equipment or pneumatic pumps actuated by gas pressure. Different pump types have different advantages with respect to reliability, precision, remote operation, simplicity, maintenance frequency, efficiency, and equipment compatibility.

Velocity Tubing

The velocity at which gas flows through pipe determines

the capacity to lift liquids. When the gas flow velocity in a well is not sufficient to move reservoir fluids, the liquids will build up in the well tubing and eventually block gas flow from the reservoir. One option to overcome liquid loading is to install smaller diameter production tubing or 'velocity tubing'. The cross-sectional area of the conduit through which gas is produced determines the velocity of flow and can be critical for controlling liquid loading. A velocity string reduces the cross-sectional area of flow and increases the flow velocity, achieving liquid removal while limiting blowdowns to the atmosphere.

Exhibit 3 shows that the conduit for gas flow up a wellbore can be either production tubing, the casing-tubing annulus or simultaneous flow through both the tubing and the annulus. In any case, a 2004 study estimated that gas velocity must be at least 5 to 10 ft/sec (300 to 600 ft/min) to effectively remove hydrocarbon liquids from a well, and at least 10 to 20 ft/sec (600 to 1200 ft/min) to move produced water. As a rule of thumb, gas flow velocity of 1,000 feet per minute is needed to remove liquid. These figures assume used pipe in good condition with low relative roughness of the pipe wall.



Source: S. Bumgardner, Advanced Resources International, inc.

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

(Cont'd)

The installation of a velocity string is relatively simple and requires calculation of the proper tubing diameter to achieve the required velocity at the inlet and outlet pressures of the tubing. Velocity tubing to facilitate liquid removal can be successfully deployed in low volume gas wells upon initial completion or near the end of their productive lives. Candidate wells include marginal gas wells producing less than 60 Mfcd. Installation of velocity tubing requires a well workover rig to remove the existing production tubing and place the smaller diameter tubing string in the well.

Coiled tubing may also be used, allowing for easier installation and the application of a greater range of tubing diameters as small as 0.25 inches. Coiled tubing can be applied in wells with lower velocity gas production due to better relative roughness characteristics of the tubing and the absence of pipe joint connections. Studies indicate that seamed coiled tubing provides better lift characteristics due to the elimination of turbulence in the flow stream because the seam acts as a “straightening vane”.

Plunger Lift with ‘Smart’ Well Automation

Plunger lifts are commonly used to lift fluids from gas wells. A plunger lift system is a form of intermittent gas lift that uses gas pressure buildup in the casing-tubing annulus to push a steel plunger and a column of fluid above the plunger up the well tubing to the surface. Exhibit 4 shows a conventional plunger lift installation on a gas well.



Source: Chesapeake Energy

The operation of a plunger lift system relies on pressure buildup in a gas well during the time that the well is shut-in (not producing). The well shut-in pressure must significantly exceed the sales line pressure in order to lift the plunger and load of accumulated fluid to the surface against the sales line backpressure. A companion Lessons Learned paper, *Installing Plunger Lift Systems in Gas Wells*, discusses the installation, gas savings and economics of plunger lift systems. The focus of the present Lessons Learned paper are the incremental gas savings obtained from installing ‘smart’ automation systems to better manage the operation of plunger lift installations on a field-wide or basin-wide scale.

Most plunger systems operate on a fixed time cycle or on a preset differential pressure. Regardless of activation system (manual, fixed time cycle, or preset pressure differential), a valve mechanism and controller at the surface cause gas volume and pressure to build up in the wellbore initiating the plunger release cycle. At this point, the surface valve closes and the plunger drops to the bottom of the well. Once adequate pressure is reached, the surface valve opens and the plunger rises to the surface with the liquid load. Insufficient reservoir energy, or too much fluid buildup can overload a plunger lift. When that occurs, venting the well to the atmosphere (well blowdown) instantaneously reduces the backpressure on the plunger and usually allows the plunger to return to the surface.

Automated control systems optimize plunger lift and well unloading operations to prevent overloading (plunger cannot overcome backpressure and rise to the surface) and underloading (plunger rises too quickly, possibly damaging equipment) therefore reducing or eliminating well venting. “Smart” automated control systems combine customized control software with standard well control hardware such as remote terminal units (RTUs) and programmable logic controllers (PLCs) to cycle the plunger system and lift fluids out of the tubing. The artificial intelligence component of a smart automation system monitors the tubing and sales line pressures and allows the PLC to “learn” a well’s performance characteristics (such as flow rate and plunger velocity) and to build an inflow performance relationship (IPR) curve for the well. The frequency and duration of the plunger cycle is then modified to optimize well performance.

Data analysis combined with wellhead control technology is the key to an effective gas well “smart” automation system. A smart automation system stores historical well production data allowing the program to learn from experience by monitoring and analyzing wellhead instrument data. The control system relays wellhead

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

(Cont'd)

instrument data to a central computer, tracks venting times, and reports well problems and high-venting wells, all of which allow custom management of field production.

The components of a smart well automation system that must be installed on each gas well include:

- ★ remote terminal unit with PLC,
- ★ tubing and casing transmitters,
- ★ gas measurement equipment,
- ★ control valve, and
- ★ plunger detector.

Automated controllers at the wellhead monitor well parameters and adjust plunger cycling. These typically operate on low-voltage, solar batteries. Exhibit 5

Exhibit 5: Typical Wellhead Equipment and Telemetry for Automated Control Systems for Plunger Lift

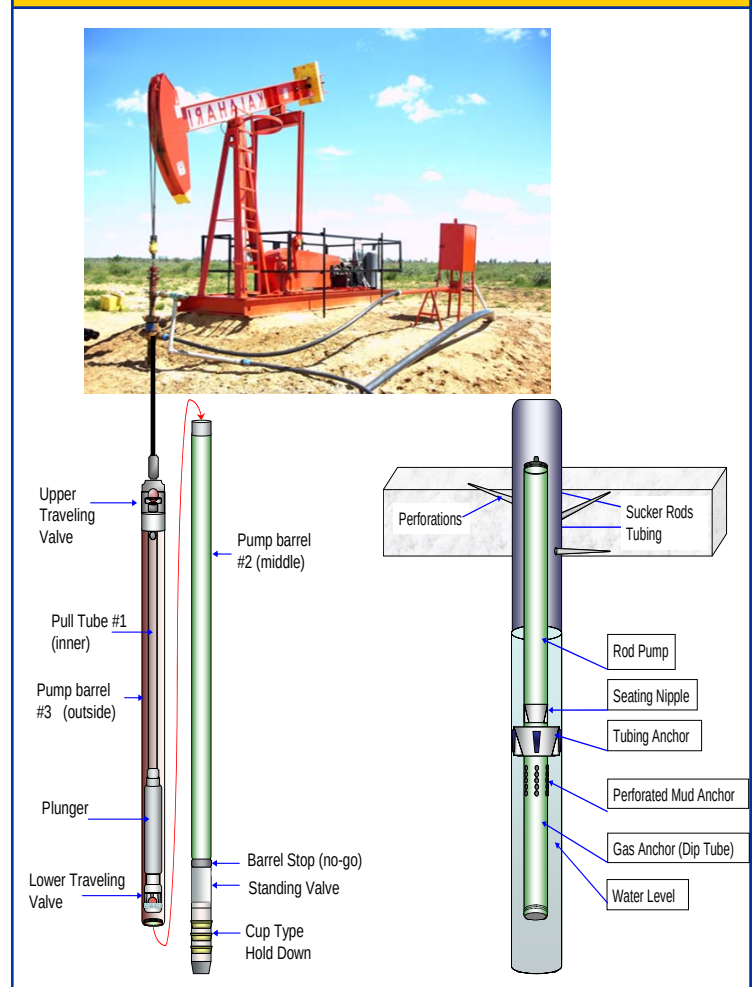


Source: BP

illustrates typical wellhead equipment and telemetry for plunger lift automated control systems. A host system capable of retrieving and presenting data is also required for continuous data logging and remote data transition. Operators configure all controls and send them to the RTU from the host system. Engineering time is needed to customize the control software and optimize the system. Field operating practices and protocols must be flexible to quickly address well performance deficiencies and operating problems.

Partners have found that optimized plunger lift cycling to remove liquids can decrease the amount of gas vented by up to 90+ percent. Methane emission savings from reduced well venting is a significant benefit that can add up to huge volumes when applied on a field or basin scale.

Exhibit 6: Diagram of a Sucker Rod Pump and Pump Jack



Source: S. Bumgardner, Advanced Resources International, inc.

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Rod Pumps and Pumping Units

A downhole positive displacement, reciprocating rod pump with surface pump unit can be deployed in the later stages of a well's life to remove liquids from the wellbore and maximize production until the well is depleted (Exhibit 6). Pumping units can be installed when there is insufficient reservoir pressure to operate a plunger lift. The units can be manually controlled by the field pumper, or very low volume wells may be operated with a timer.

Pumping units not only eliminate the need to vent the well to unload fluids but also extend the productive life of a well. Methane emissions can be further reduced by operating pumping units with electric motors, rather than natural gas-fueled engines. The annual fuel requirement for a typical pumping unit is approximately 1,500 Mcf per unit, of which 0.5 percent is emitted as unburned methane (8 Mcf per unit per year).

A well workover rig is required to install the downhole rod pump, rods, and tubing in the well. Field personnel must be trained for rod pump operations and proper maintenance of the surface equipment. Excessive wear of the rods and tubing can be a major expense for rod pump applications where solids are produced or down hole corrosion is a problem.

A common problem with reciprocating pumps in gas wells is gas locking of the rod pump valves, which prevents the pump from delivering fluid to the surface at the design rate. The presence of free gas in the subsurface sucker rod pump decreases the volumetric pump efficiency and can prevent the pump from lifting fluid. This is not a problem found in progressive cavity pumps as there are no valves to gas lock.

Economic and Environmental Benefits

Implementation of fluid removal options and artificial lift provide economic and environmentally beneficial alternatives to well blowdown. The major benefit of the

various fluid removal options is extending the productive life of a well. The full scope of environmental and economic benefits depend on the type of artificial lift system and the remaining productive capacity of the well. Several benefits described below, are realized with the progressive application of fluid removal options in gas wells.

- ★ **Improved gas production rates and extended well life.** Fluid removal and artificial lift systems conserve reservoir energy and boost gas production. Regular fluid removal generally extends the economic life of declining wells resulting in more continuous gas production, improved gas production rates, and incremental ultimate recovery.
- ★ **Reclaims vented gas to sales.** Avoiding well blowdown reclaims the value of gas that would otherwise be vented to the atmosphere.
- ★ **Reduced pollution.** Eliminating well blowdown and gas venting eliminates a significant source of methane and other air pollutant emissions.
- ★ **Lower well maintenance costs and fewer remedial treatments.** Overall well maintenance costs can be reduced by eliminating the cost of a workover rig for swabbing wells. Other savings occur when well blowdowns are significantly reduced or eliminated.

Decision Process

The decision to implement any type of liquid removal option during the life-cycle of a gas well should be made when the value of the estimated incremental gas production exceeds the cost of the fluid removal option. When one fluid removal approach becomes ineffective and uneconomic, another can be deployed. If venting a well is the current fluid removal approach, the application of foaming agents, velocity tubing or plunger lift should be evaluated before well blowdowns become too frequent, less effective and costly. Natural Gas STAR Partners can use the following decision process as a guide to evaluate the application, safety, and cost effectiveness of fluid removal and artificial lift installations.

Step 1: Determine the technical feasibility of a fluid removal option or artificial lift installation.

Various data and criteria should be evaluated to select a fluid removal approach that is both technically feasible and cost effective. These data include IPR (inflow

Four Steps for Evaluating Artificial Lift Options:

- Determine the technical feasibility of various artificial lift options.**
- Determine the cost of various options.**
- Estimate the natural gas savings and production increase.**
- Evaluate and compare the economics of artificial lift options.**

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

(Cont'd)

performance relationship) curves; reservoir pressure; gas and fluid production flow rates; fluid levels in the well; the desired flowing bottom hole pressure and casing pressure; production tubing size, the downhole condition of the well; other mechanical limitations of the well and production site; and the capabilities and training of field personnel.

Appendix A (Exhibit A1 and A2) shows the Turner relationship and Lee relationship between critical flow rate (critical gas velocity), and flowing pressure for various sizes of production tubing. If the relationship between flow rate and pressure falls below a line specifying a size of production tubing, a well will not flow liquids to the surface for the indicated tubing size. If flow rate vs pressure falls on or above the line for a specified tubing size, a well meets or exceeds the critical flow rate for the specified tubing size and the well is able to unload fluid to the surface. Exhibits A1 and A2 can be used as starting points to estimate whether a fluid removal or artificial lift option is likely to be effective. Following are some technical considerations that enter into the decision process for each fluid removal option:

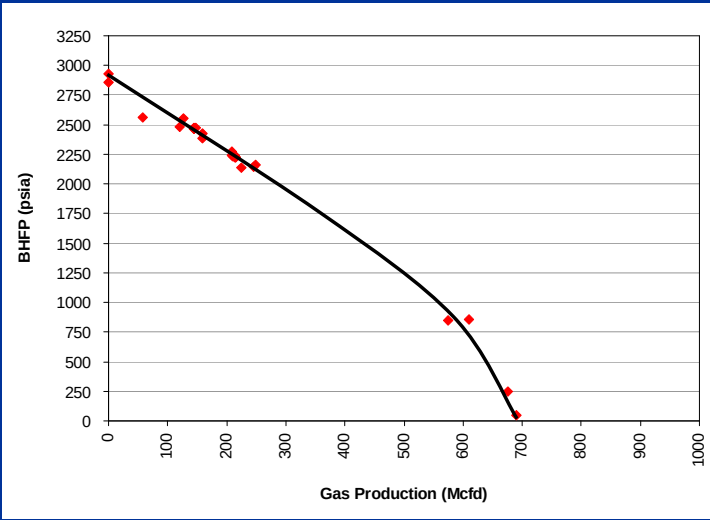
- ★ **Foaming Agents.** Partners typically use foaming agents early in the life of gas wells when the wells begin to load with formation water and the liquid production rate is comparatively low. Foaming works best if the liquid in the wellbore is mainly water, and condensate content is less than 50 percent. Foaming agents may also be used in combination with other well treatments that reduce salt and scale build up, or may be applied in combination with velocity tubing.
- ★ **Velocity Tubing.** Velocity tubing strings are appropriate for natural gas wells with relatively small liquid production and higher reservoir pressure. Low surface pipeline pressure relative to the reservoir pressure is also necessary to create the

pressure drop that will achieve an adequate flow rate. The depth of the well affects the overall cost of the installation, but is usually offset by the higher pressure and gas volume in deeper wells. Velocity tubing can also be a good option for deviated wells and crooked well bores. Rod pumped wells with deviation and or dog legs that become uneconomic due to high failure rates and servicing costs may also be candidates for velocity strings.

Determining the feasibility of installing a velocity tubing string is relatively straightforward. An inflow performance relationship (IPR curve) is calculated to establish the flow regime in the well tubing, as shown in Exhibit 7. The diagram shown in Exhibit 7 illustrates the relationship between gas production and the bottom hole flowing pressure (BHFP). Gas flow is evaluated and the velocity relationships for various sizes of tubing are developed to determine the appropriate diameter for use in each well. As a rule of thumb, a gas flow velocity of approximately 1,000 feet per minute is the minimum necessary to remove fresh water. Condensate requires less velocity due to its lower density while more dense brine requires a higher velocity.

Once the velocity string is installed, no other artificial lift equipment is required until the reservoir pressure declines to the point that

Exhibit 7: Example of Inflow Performance Relationship Curve for Evaluating Fluid Removal Options



Source: S. Bumgardner, Advanced Resources International, inc.

Indicators of Liquid Loading in Gas Wells:

1. Construct an IPR curve and evaluate the production efficiency of the well.
2. Monitor production curves for each well on a regular basis. Liquid loading is indicated if the curve for a normally declining well becomes erratic and the production rate drops.
3. Compute the critical gas velocity (flow rate) at which liquid can no longer be lifted in the tubing (see Appendix)
4. Critical velocity vs. flowing tubing pressure can be constructed for various tubing diameters.

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(Cont'd)

velocities of 1,000 feet per minute are no longer possible in the tubing. The introduction of a foaming agent to the bottom of a tubing string will extend the effective life of a velocity string below the 1,000 feet per minute velocity required to lift water by reducing the density of the column that is lifted. This only applies to water lifted from the well tubing since condensate is not affected by a surfactant.

- ★ **"Smart" Well Automation of Plunger Lift.** Candidate wells for plunger lift generally do not have adequate downhole pressure for the well to flow freely into a gas gathering system. Like pumping units, plunger lifts are used to extend the productive life of a well. Installation is less expensive than rod pumps, but plunger lifts may be difficult to operate.

Conventional plunger lift operations rely upon manual, on-site adjustments to tune a plunger cycle time. When a plunger lift becomes overloaded, the well must be manually vented to the atmosphere to restart the plunger. A "smart" well automation system enhances plunger performance by monitoring parameters such as tubing and casing pressure, well flow rate and plunger cycle frequency (travel time). Data for each well are relayed to a host computer where operators review the data and address any performance deficiencies or operating problems. This helps to optimize plunger lift performance, improve gas production, and reduce well venting.

Optimum plunger lift performance generally occurs when the plunger cycle is frequent and set to lift the smallest liquid loads. Small liquid loads require lower operating bottom hole pressure, which allows for better inflow performance. As with velocity tubing, a desirable velocity for a plunger to ascend in tubing is in the range of 500 to 1,000 ft per minute.

- ★ **Pumping Units.** Rod pump installations for gas wells can be costly to install and operate, but can extend well life, increase ultimate recovery, increase profits and reduce methane emissions. A rod pumping application for gas wells must be carefully designed to ensure trouble-free installation of the pumping units, minimize installation costs, and maximize operating cost savings by reducing mechanical wear and the need for well servicing.

Technical considerations for a rod pump application include the amount of pump capacity required, the pump setting depth in the well, and the type and

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

gravity of the fluid in the hole (brine, fresh water, hydrocarbon, hydrogen sulfide, carbon dioxide, etc.). These factors influence the components of a rod pump installation, including rod pump materials, rod string size and grade, pumping unit design, size of the prime mover (motor), pump speed and stroke length. Resources available for evaluating and designing rod pump applications for gas wells include American Petroleum Institute and various Society of Petroleum Engineers publications; commercial pumping unit vendors; and computer design models. In general, rod pump installations for gas wells have lower fluid volumes than for oil wells. Operating costs can be minimized by correctly sizing the artificial lift and pumping as slow as possible while maintaining a pumped-off condition. The use of pump-off controllers are also effective by matching the pump displacement to the volume of fluid entering the well bore.

Step 2. Determine the cost of fluid removal options.

Costs associated with the various fluid removal options include capital, start-up and labor expenditures to purchase and install the equipment, as well as ongoing costs to operate and maintain the systems.

- ★ **Foaming Agents.** Partners report upfront capital and start-up costs to install soap launchers ranging from \$500 to \$3,880 per well. Monthly cost for the foaming agent is \$500 per well, or approximately \$6,000 per year. As such, typical costs can vary between \$500 and \$9,880.
- ★ **Velocity Tubing.** One Partner reports total capital and installation costs of at least \$25,000 per well, which includes the workover rig time, downhole tools, tubing connections and supervision. Another Partner has deployed velocity tubing in more than 100 wells and reports total installation costs ranging from \$8,100 per well to \$30,000 per well. Based on Partner experiences, typical costs will vary between \$7,000 and \$64,000 per well.

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

(Cont'd)

★ **“Smart” Well Automation of Plunger Lift.** Two Partners report implementing “smart” automation systems to control plunger lift operations. One operation is fairly small, consisting of 21 wells. The second is a basin-wide deployment on more than 2,150 wells. Reported upfront costs for the smaller installation is \$6,300 per well. Total cost over 5 years reported for the larger automation project is \$12,200,000 or approximately \$5,700 per well. Typical costs will vary between \$5,700 and \$18,000 depending on the complexity of the “smart” automation system. These costs would be incremental over the cost of installing a plunger lift system.

★ **Pumping Units.** Capital and installation costs include the use of a workover rig and crew, for approximately one day, sucker rods, rod guides and pump costs, and the cost of the pumping unit and motor. Other start-up costs can include miscellaneous clean out operations to prepare the well to receive a down hole pump and sucker rods.

Partners report that location preparation, well clean out, artificial lift equipment, and a pumping unit can be installed for approximately \$41,000 to \$62,000 per well. The reported average cost of the pumping unit alone appears to range from approximately \$17,000 to \$27,000. Most companies have surplus units in stock that can be deployed at the expense of transportation and repair, or may purchase used units.

Step 3. Estimate the savings from various fluid removal options.

The total savings associated with any of the fluid removal and artificial lift options include:

- ★ Revenue from incremental increased gas production;
- ★ Revenue from avoided emissions;
- ★ Additional avoided costs such as well treatment and workover costs, and reduced fuel and electricity;
- ★ Salvage value.

Revenue from Increased Production

The most significant benefit of deploying foaming agents, velocity tubing or a pumping unit is to extend the productive life of the well by decreasing the abandonment

pressure of the reservoir and increasing the cumulative gas production. The benefit of automating a plunger lift system is to optimize the plunger cycle. Most of the increase in gas production is realized by the initial decision to install plunger lifts. Installing a ‘smart’ automated control system provides some incremental increase in gas production over a plunger lift system operated manually or by a timer, but the most significant benefit is the emissions avoided from repeated well blowdowns and the reduction in personnel time required at the well.

The fluid removal options are evaluated based on the incremental gas production predicted by well blowdowns. For wells that are not on production decline, the incremental gas production from installing velocity tubing or artificial lift can be estimated by assuming the average peak production after a well blowdown event represents the incremental peak production that will be achieved after the fluid removal option is implemented in the well.

The more common evaluation is for a well already experiencing production decline. In such a case, estimating incremental gas production from implementing a fluid removal/ artificial lift method is more complex and requires generating a new “expected” production and decline curve that would result from reducing the back pressure at the well perforations. This requires well-specific reservoir engineering analyses, a basic example of which is provided in Appendix B.

Once the incremental gas production from implementing a fluid removal approach is estimated, operators can

Exhibit 8: Gas Production Increase from Application of Foaming Agents — One Partner’s Experience

- One Gas STAR Partner reports injecting foaming agent into 15 wells using soap sticks.
- Incremental gas production of individual wells increased an average of 513 Mcf per well per year.
- Annual incremental gas production for the entire project was 7,700 Mcf.
- Total cost for the project was \$8,871 in 2010 dollars.
- At nominal gas prices ranging from \$3.00/ Mcf to \$5.00/ Mcf, the value incremental gas production ranges from approximately \$23,100 to \$38,500/ year and project payback occurs in 3 to 5 months.

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

(Cont'd)

calculate the value of the incremental gas and estimate the economics of the application. Exhibit 8 is an example of the potential revenue from increased gas production using foaming agents. Note that Exhibit 8 does not include other benefits such as avoided blowdown emissions and operations cost savings.

Revenue from Avoided Emissions

Emissions from venting gas to the atmosphere vary in both frequency and flow rates, and are entirely well and reservoir specific. The volume of natural gas emissions avoided by reducing or eliminating well blow-downs will vary due to individual characteristics such as sales line pressure, well shut-in pressure, fluid accumulation rate, and well dimensions (such as depth and casing and tubing diameters). Another key variable is an operator's normal practice for venting wells. Some operators put wells on automatic vent timers. Some wells are vented manually with personnel standing by monitoring the blow-down. In some cases, wells are open to vent and unattended for hours or days, depending upon the time it typically takes the well to clear liquids. The economic benefits of avoided emissions will vary considerably, and some projects will have significantly shorter payback periods than others.

Partner-reported annual emissions attributable to well blowdowns vary from 1 Mcf per well to several thousand Mcf per well, so methane emissions savings attributable to

avoided emissions will also vary according to the characteristics and available data for the particular wells being vented. Exhibit 9 illustrates the range of avoided emissions reported by various Partners after applying specific fluid removal and artificial lift strategies in their operations.

Revenue from avoided emissions can be calculated by multiplying the sales price of the gas by the volume of vented gas. If well emissions have not been measured, they can be estimated. The volume of emissions from well venting can be estimated by constructing an IPR curve to predict the open flow potential of the well based on reservoir pressure, depth, tubular sizes, and fluid constituents. Other operator methods are discussed in Appendix C. The volume of gas released during well blow-down is dependent on the duration of the event, wellhead temperature and pressure, size of the vent line, the properties of the gas, and the quantity of water produced.

Four approaches to estimating well blow-down emissions are provided in Appendix C. None of the estimations discussed in Appendix C provide the "exact" result in an absolute sense, but they are accurate enough for effective management of producing gas wells. One emission estimation approach calculates well blow-down volume as a function of venting time, normal production rate, well volume and gas properties. Another approach uses

Exhibit 9: Comparison of Partner-Reported Costs and Emissions Savings for Fluid Removal / Artificial Lift Options

Fluid Removal Approach	Installation Costs (\$/well)	Incremental Gas Production (Mcf/well/year)	Avoided Methane Emissions from Swabbing/ Blowdown ² (Mcf/Well/Year)	Other Potential Cost Savings (\$/well)
Use Foaming Agents	\$500 - \$9,880 (installation of soap launcher); \$500/month (surfactant)	365 – 1,095	178 – 7,394	\$2,000 (eliminate well swabbing)
Install Velocity Tubing	\$7,000 - \$64,000	9,125 – 18,250	146 – 7,394	\$2,000 - \$13,200 (eliminate well swabbing & blowdown)
"Smart" Well Automated Controls for Plunger Lift¹	Partner reported average cost = \$5,700 - \$18,000	Not reported by Partners (5,000 Mcf estimated for average U.S. gas well by assuming a 10-20% increase in production)	Partner reported = 630 – 900 (500 Mcf estimated for average U.S. well by assuming 1 % of annual production)	\$7,500 (reduces labor cost to monitor plunger lift installations in the field)
Install Rod Pumps and Pumping Units	\$41,000 - \$62,000	Not reported	769 – 1,612	\$22,994 (salvage value at end of well life)

¹Incremental cost, gas production and methane emissions savings for installation of automated plunger lift control system.

²Assumes methane content of natural gas at wellhead is 79 percent, unless reported otherwise.

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

(Cont'd)

pressure transient analysis to extrapolate gas flow rate from wellhead pressure. A final approach installs an orifice meter on a vent line and measures specific vent volume over time. The resulting vent rates expressed in Mcf/minute are averaged by producing formation and extrapolated from the initial subset of wells measured to the larger well population.

Avoided Costs and Other Benefits

Avoided costs and additional benefits depend on the type of fluid removal/ artificial lift system currently applied in the well and the new system to be deployed. These can include avoided chemical treatments, fewer well workovers, lower fuel costs and lower daily operations and maintenance costs. Partners report using foaming agents to replace well swabbing for a savings of approximately \$2,000 annually per well. EPA's Natural Gas STAR Partners report that "smart" well automated control systems for plunger lifts have reduced the labor cost for field monitoring by approximately \$7,500 per well. Velocity tubing eliminates well swabbing, well blowdowns and chemical treatments, the cost of which are reported to range from a few thousand to more than \$13,000 per treatment.

Step 4. Evaluate the economics of fluid removal options.

Basic cash flow analysis can be used to compare the costs and benefits of the various fluid removal options. Exhibit 9 is a summary of the installation costs, gas savings and reduced methane losses associated with each fluid removal

approach that have been reported by Natural Gas STAR Partners. Cash flow analyses based on Partner-reported experience and data are provided in Exhibit 10 for installing velocity tubing strings and in Exhibit 11 for "smart" well automated control systems for plunger lift.

Partner Experience

This section highlights specific experiences reported by Gas STAR Partners with the selected fluid removal options for gas wells.

Install Velocity Tubing Strings.

One Partner reported installation of velocity tubing in two Gulf Coast wells during 2008. Total installation cost in 2008 was \$25,000 per well, which included a workover rig to remove and replace tubing, downhole tools, connections and supervision. Due to low inflation between years 2008 and 2010, the installation cost in 2010 dollars is only slightly higher than 2008.

The velocity tubing installation in these wells improved gas production by 25 Mcfd to 50 Mcfd, which equates to annual incremental gas production of approximately 9,125 Mcf to 18,250 Mcf per well. In addition, gas savings from eliminating well swabbing is 160 Mcf per year per well. Methane content of gas at the well head is 91 percent, so the estimated reduction in methane losses are 146 Mcf per well. Velocity tubing also eliminated annual swabbing costs of approximately \$2000 per well per year. Exhibit 10

Exhibit 10: Economic Analysis of Velocity Tubing Installation Replacing Periodic Swabbing

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Value of Gas from Increased Production¹		\$36,500	\$36,500	\$36,500	\$36,500	\$36,500
Value of Gas from Avoided Emissions²		\$640	\$640	\$640	\$640	\$640
Velocity Tubing Installation Cost	(\$25,000)					
Avoided Swabbing Cost		\$2,000	\$2,000	\$2,000	\$2,000	\$2,000
Net Annual Cash Flow	(\$25,000)	\$39,140	\$39,140	\$39,140	\$39,140	\$39,140
Internal Rate of Return = 155% NPV (Net Present Value)³ = \$112,156 Payback Period = 8 months						

¹ Gas valued at \$4.00/ Mcf for 9,125 Mcf/well (25 Mcfd) due to increased gas production

² Gas valued at \$4.00/Mcf for 160 Mcf /well of avoided gas emissions due to elimination of well swabbing

³ Net present value based on 10 percent discount rate over 5 years

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

(Cont'd)

provides a cash flow analysis of this Partner's velocity tubing installation replacing well swabbing.

Install "Smart" Automated Control Systems on Plunger Lifts

Two Partners have applied "smart" well automated control systems at plunger lift installations. One Partner—BP—initiated an automation project in 2000, and in 2001 began installing automated plunger lift control systems across their San Juan Basin operations. BP justified the project based on gas and methane emissions savings resulting from a 50 percent reduction in well venting between 2000 and 2004. By 2007, BP implemented automated control systems for more than 2,150 wells equipped with plunger lift which resulted in average methane emissions savings of 900 Mcf per well. Total cost for the "smart" automation systems was \$12.2 million. Total gas venting was reduced from approximately 4 billion cubic feet of gas per year (Bcf) to approximately 0.8 Bcf.

Another Natural Gas STAR Partner found that a substantially smaller application of "smart" automated controls for plunger lift can be similarly effective. An automated control system was implemented for 21 wells equipped with plunger lifts. Total gas savings are 16,800 Mcf per year, or 800 Mcf per well. Assuming a methane content of 79 percent, estimated annual methane emissions savings are 632 Mcf per well.

The wide range in upfront capital and installation costs for components of plunger lift automated control systems are indicated in Exhibit 9. The host computer and communication system can be quite costly (\$50,000 to \$750,000) depending upon the size of the project, but as more plunger lift-equipped wells are added, the unit cost for the automated control system is significantly reduced. The two Natural Gas STAR Partners report approximate unit costs for plunger lift automated control systems of \$6,800 and \$5,950 per well, respectively. Exhibit 11 provides a basic cash flow analysis of "smart" well automated control systems for plunger lift based on

Exhibit 11: Economic Analysis of "Smart" Well Automated Control Systems for Plunger Lift for Hypothetical Onshore Gas Field¹

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Value of Gas from Increased Production²		\$220,000	\$220,000	\$220,000	\$220,000	\$220,000
Value of Gas from Avoided Emissions³		\$40,000	\$40,000	\$40,000	\$40,000	\$40,000
Install RTUs at Wells, \$ (\$11,000/well x 20 wells)	(\$220,000)					
Install Host Computer / Communication (\$50K - - \$750K)	(\$200,000)					
Avoided Labor Cost for Field Monitoring (\$7500/well x 20 wells)		\$150,000	\$150,000	\$150,000	\$150,000	\$150,000
Net Cash Inflow	(\$420,000)	\$410,000	\$410,000	\$410,000	\$410,000	\$410,000
Internal Rate of Return = 94 % NPV (Net Present Value)⁴ = \$1,031,111 Payback Period = 12.3months						

¹ Assumes production from average US gas well is 50,000 Mcf/Year

² Gas valued at \$4.00/Mcf for 5,000 Mcf /well of increased gas production due to optimized plunger lift operation; equivalent to 10% of production for average US onshore gas well. Assumes 20 wells in project.

³ Gas valued at \$4.00/Mcf for 500 Mcf of gas savings due to reduced well blowdown/venting; equivalent to 1% of production for average US onshore gas well. Assumes 20 wells in project.

⁴ Net present value based on 10 percent discount rate over 5 years

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

(Cont'd)

generic assumptions about potential increased gas production and methane emissions savings for the average onshore natural gas well in the United States.

Install Pumping Units on Wells Lifting Low Water Volumes

ConocoPhillips installed pumping units on 45 low-pressure gas wells in 2003 to remove low water volumes from the wells and prevent them from loading up. This installation eliminated routine venting of the wells for up to one hour per day. The primary benefit of installing pumping units on these wells is the incremental gas production gained by extending the productive life of the wells. The Partner reported gas savings of 973 Mcf per well from the elimination of well blowdowns as a secondary, but not insignificant, benefit. The pump jacks at this installation are powered by electric motors rather than natural gas engines, which contributes to fewer methane emissions and lower maintenance costs.

ConocoPhillips reported total gas savings of 43,780 Mcf for the project or approximately 973 Mcf per well per year. At a nominal gas price of \$4.00 to \$5.00/Mcf, this corresponds to savings of approximately \$3,892 to \$4,865 per unit, or \$175,140 to \$218,900 per year for the entire project consisting of 45 wells. Assuming a methane content of 79 percent, this project has reduced methane losses by 34,586 Mcf per year.

Total capital and installation costs for the downhole pumps and surface pumping units were estimated to be \$62,000 per well in 2003 or the equivalent of \$73,332 in 2010 dollars. The total cost in 2003 included \$45,000 for

site preparation, downhole equipment, and installation plus an average cost of \$17,000 per pumping unit. The project was expanded in subsequent years. ConocoPhillips reported a total of 100 pumping units installed from 2005 through 2007. During this time, the average reported upfront installation cost declined to approximately \$38,000 per unit in 2010 dollars. Assuming a nominal gas price of \$4, the vented gas savings alone pays back the typical pumping unit installation for this project in less than 10 years.

Lessons Learned

- ★ For natural gas wells, a progression of fluid removal options are available to unload accumulated fluid, boost gas production, extend well life and reduce or eliminate the need for well venting.
- ★ Options for removing accumulated wellbore fluids from gas wells range from relatively low cost application of surfactants, appropriate for wells with low fluid production and significant remaining reservoir energy, to installing pumping units and downhole rod pumps on wells with depleted reservoir pressure and significant water production.
- ★ The best approach will depend on the where a well is performing along the continuum of its productive life.
- ★ Well blowdown and swabbing can release large volumes of natural gas to the atmosphere, producing significant methane emissions and gas losses.
- ★ Fluid removal approaches presented in this paper can reduce the amount of remedial work needed during the lifetime of a well, eliminate well blowdowns, and increase the ultimate recovery of the well while minimizing methane emissions to the atmosphere.
- ★ If a well is in production decline, the fluid removal alternatives discussed here will increase gas production in most cases or at least arrest the decline.
- ★ This increased gas production should be captured in analyses of cash flow and future economic benefit when evaluating fluid removal options for gas wells. In most cases, increased gas production is the primary benefit from implementing any or all of the fluid removal options.

Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

(Cont'd)

- ★ Methane emissions and gas savings from the elimination of well venting is generally a secondary, but significant, benefit, which may cover all or most of the upfront installation costs for a fluid removal technology.

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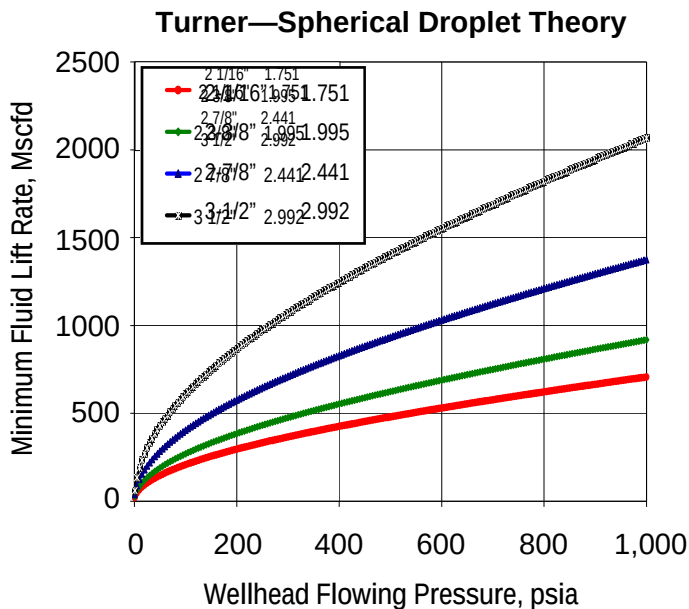
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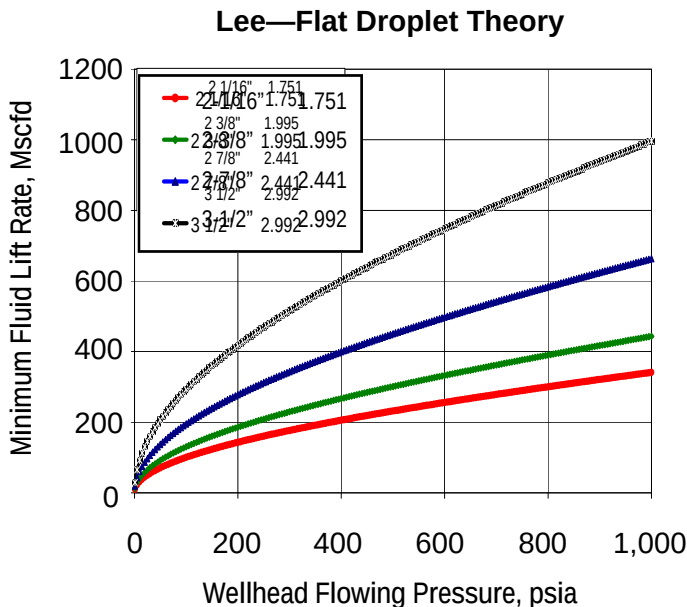
APPENDIX A: Estimating the Critical Flow Rate to Remove Liquids from Production Tubing

Exhibit A1: Turner Unloading Rate for Well Producing Water



Source: S. Bumgardner, Advanced Resources International, inc.

Exhibit A2: Lee Unloading Rate for Well Producing Water



Source: S. Bumgardner, Advanced Resources International, inc.

APPENDIX B: Estimating Incremental Production for Declining Wells

From Dake's Fundamentals of Reservoir Engineering (1978) the following analytical model can be used to estimate increased gas flow into a well in response to reducing back pressure on the perforations by removing accumulated liquids. The semi-steady state inflow equation is:

$$m(p_{avg}) - m(p_{wf}) = \left[\frac{(1422 \times Q \times T)}{(k \times h)} \right] \times [\ln(r_e/r_w) - 3/4 + S] \quad (8.15)$$

Where,

$m(p_{avg})$ = real gas pseudo pressure average

$m(p_{wf})$ = real gas pseudo pressure well flowing

Q = gas production rate

T = absolute temperature

k = permeability

h = formation height

r_e = external boundary radius

r_w = wellbore radius

S = mechanical skin factor

Incremental production achieved by implementing various artificial lift options can be estimated by solving this equation for 'Q' calculated for retarded flow with fluids in the hole (current conditions and current decline curve), and comparing to 'Q' calculated for the condition of no fluids in the hole (artificial lift active and improved decline curve). This discussion is intended as a guide for estimating the potential impact of fluid removal alternatives, and is not a substitute for thorough reservoir engineering analyses of specific wells.

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

(Cont'd)

APPENDIX C: Alternate Techniques for Estimating Avoided Emissions When Replacing Blowdowns

Simple Vent Volume Calculation

A conservative estimate of well venting volumes can be made using the following equation:

$$\text{Annual Vent Volume, Mscf/yr} = (0.37 \times 10^{-6}) * (\text{Casing Diameter}^2) * (\text{Well Depth}) * (\text{Shut-in Pressure}) * (\text{\# of Annual Vents})$$

Where, casing diameter is in inches, well depth is in feet and shut-in pressure is in psia. If the shut-in pressure is not known, a suitable surrogate is the casing pressure at the surface.

This is the minimum volume of gas that would be vented to atmospheric pressure from a well that has stopped flowing to the sales line because a head of liquid has accumulated in the tubing equal to the pressure difference between the sales line pressure and well shut-in pressure.

If the well shut-in pressure is more than 1.5 times the sales line pressure, as required for a plunger lift installation, then the volume of gas in the well casing at shut-in pressure should be minimally sufficient to push the liquid in the tubing to the surface in slug-flow when back-pressure is reduced to sales line pressure.

Partners can estimate the minimum time needed to vent the well by using this volume and the Weymouth gas-flow formula (worked out for common pipe diameters, lengths and pressure drops in Tables 3, 4 and 5 in *Pipeline Rules of Thumb Handbook*, Fourth Edition, pages 283 and 284). If a Partner's practice is to open and vent the wells for a longer time than calculated by these methods, the Annual Vent Volume calculated by this equation can be scaled up according to the ratio of the actual vent time versus the minimum vent time calculated using the Weymouth equation.

Natural Gas STAR Partner, BP, has reported three approaches to estimating well venting and completion emissions, which include: 1) a more detailed version of the vent volume calculation method above, 2) pressure transient analysis, and 3) installing an orifice meter on the vent line.

Detailed Vent Volume Calculation

The detailed vent volume calculation is a function of

venting time, normal production rate, and “well blowdown value” that represents the volume of gas in a well under an assumption of line pressure.

$$\text{Vent Volume (Mcf)} = ((\text{Vent Time} - 30 \text{ min}) * (1/1440) * \text{Production Rate}) + (\text{Well Blowdown Volume})$$

$$\text{Well Blowdown Volume (Mcf)} = (\text{well depth} * 3.1416 * (\text{casing diameter}/2)^2 * ((\text{tubing press} + \text{atmospheric press})/14.7) * (520/(\text{Temp}+460)) / Z / 1000$$

Variables:

- production rate, Mcf per day
- well depth, ft
- atmospheric pressure, psia
- shut-in tubing pressure, psig
- temperature of gas in pipeline, °F
- diameter of production casing, ft
- compressibility, Z

A limitation of the vent volume calculation method is that it does not account for either the volume or weight of a column of fluid in the wellbore at the time of venting.

Pressure Transient Analysis

This method is based on observations of wellhead pressure versus flow rate for a specific set of wells which are used to develop a linear expression of gas flow rate versus wellhead pressure. This relationship is then applied to pressure transient data during blowdown to extrapolate Mcf versus time for the venting period. All data are evaluated using pressure data analysis software to extrapolate total vented volumes based on the blowdown time, pipe diameter and the decline in well head pressure during the process. An advantage of this approach is that it accounts for choke flow and is tailored to specific wells. Limitations of the approach are that it fails to account for very large influx into the reservoir and the observations data set may not be representative of the formation. To make the data set more representative, it is recommended that the data include at least one point within the following 5 ranges:

- ★ $P \leq 25$ psia
- ★ $25 \text{ psia} < P \leq 60 \text{ psia}$

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells (Cont'd)

- ★ $60 \text{ psia} < P \leq 110 \text{ psia}$
- ★ $110 \text{ psia} < P \leq 200 \text{ psia}$
- ★ $200 \text{ psia} < P$

Orifice Metering of Blow Down

For this approach, an orifice meter is installed on a vent line and flow rates are measured directly during blowdown. An advantage of this approach is the precision of the data that are obtained, potentially offering meaningful comparisons of vent volumes between well types, well completions or producing formations.

A limitation of the approach is that results obtained from a 'study population' or small subset of producing wells will likely be extrapolated to a larger field or producing area, and the original study wells may not be representative of field operations as a whole.

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

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**United States
Environmental Protection Agency
Air and Radiation (6202J)
1200 Pennsylvania Ave., NW
Washington, DC 20460**

2011

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.

**Technical Information
Oil and Gas Sector
Significant Stationary Sources of NOx Emissions**

**Final
October 17, 2012**

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1.0 Introduction

The oil and gas exploration and production sector is a large, complex industry with a diverse array of equipment and many sources of NOx emissions. Larger sources within the sector, such as refineries and natural gas processing facilities, are reasonably well documented and are generally treated as point sources with the appropriate applicable NOx emissions limitations. However, the oil and gas sector includes many smaller, diffuse NOx emission sources that support the equipment used for the exploration for oil and gas and the subsequent transport of the oil and gas from the source in the ground to the marketplace. Many of these NOx emission sources are well distributed throughout the country, including those used to support oil or gas pipeline transportation. However, in areas where there are concentrations of oil or gas in underground reservoirs, there tends to also be a concentration of drilling operations, pumps, compressors, etc that collectively emit NOx emissions at levels that may impact air quality. These oil and gas industry NOx emissions sources are the subject of this review.

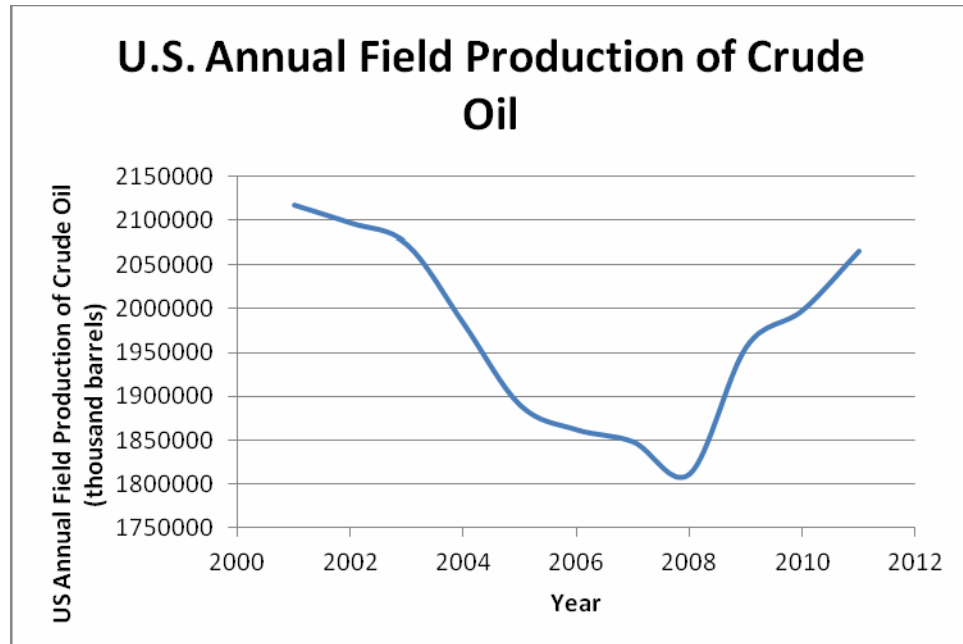
Some equipment within the oil and gas sectors **emits** NOx that may contribute to air quality problems locally and in downwind states. While much of the equipment, such as drilling rigs and well pumps and compressors, ~~are~~ **is** concentrated in areas with abundant in-situ supply of oil and/or natural gas, other sources such as refineries, gas processing plants, fuel-fired pipeline gas compressors and pipeline oil pumps are located throughout the country. This equipment operates in a wide variety of modes, with some only operating during initial phases of extracting the product from the ground, some operating almost continuously as long as the source well is productive, and some operating in a variable capacity to meet the demand for the product.

This review attempted to assemble relevant information and technical documentation regarding the combustion devices utilized in the gas and oil sector in the Northeast and Mid-Atlantic states, excluding those sources located in refineries and gas processing facilities, and to present relevant information regarding the possibility of controlling NOx emissions from those sources. The twelve states and District of Columbia that constitute the Ozone Transport Commission (OTC) are developing this document to understand the potential for reductions in emissions of nitrogen oxides (NOx) that may be available from the oil and gas sector. Reductions in NOx emissions may assist the OTC states to attain and maintain the ozone national ambient air quality standards.

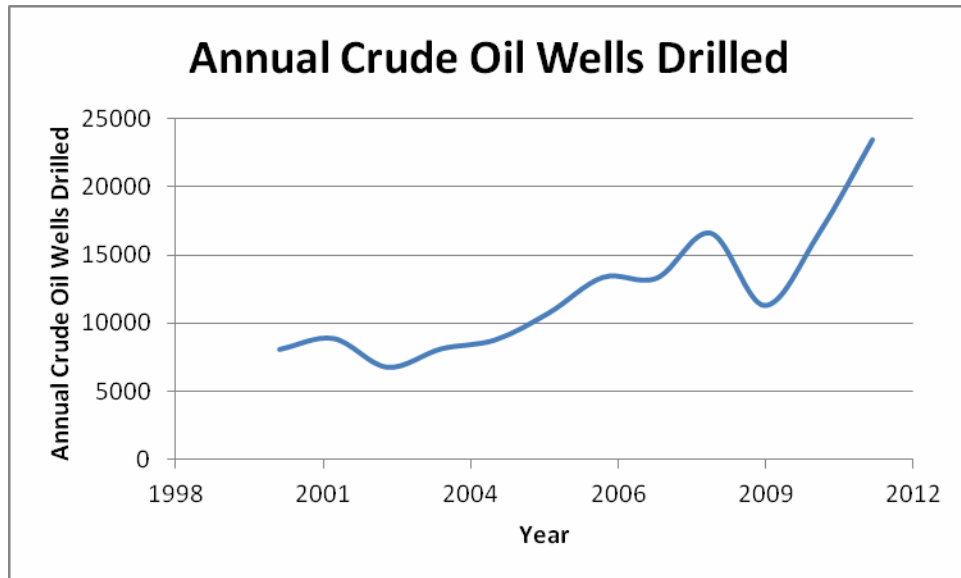
The production and consumption of natural gas have both increased dramatically in recent years, and the rate of both natural gas production and natural gas consumption is projected to continue to increase. As a result, many new sources of NOx emissions have been added to the existing inventory within the OTR (as well as surrounding states), primarily in Pennsylvania and New York. While many of these engines are small, the emissions from these small sources as a group may become an air quality problem if the existing and new equipment is not properly controlled. This document addresses the equipment used in drilling of exploratory wells and production wells for crude oil and natural gas, pumps and compressors to take the product from the well heads to the gathering system, oil and gas heaters near the well head, and pipeline pumps and compressors to transport the product to processing facilities, storage facilities, and to distribution systems. Potential emissions controls for internal combustion engines and combustion turbines that are used in the above listed applications are detailed in Section 4 of this document. The document also provides a sample of state and federal air quality laws and regulations that apply to this portion of the oil and natural gas sector.

2.0 US Annual Crude Oil and Natural Gas Production

Crude oil production in the lower 48 states has been in a general decline for a long period of time, including a portion of the last decade. However, the crude oil production has demonstrated an increase in the last few years. In the lower 48 states, the states of Texas, California, and North Dakota have been the largest crude oil producers. Within the Ozone Transport Region (OTR), the states of Pennsylvania and New York are crude oil producers. The following graph shows the US crude oil production over the last decade:

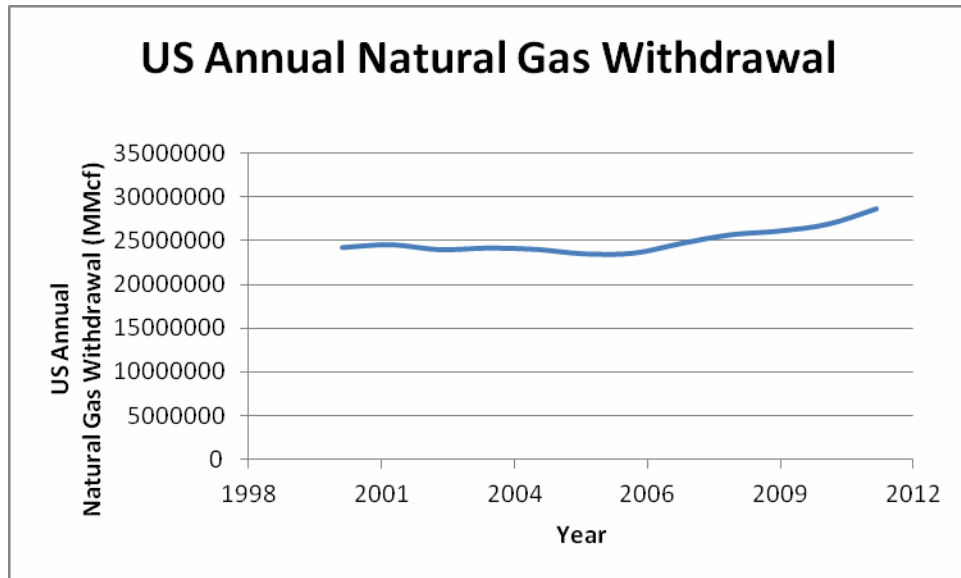


In order to maintain and increase the crude oil production across the US, new crude oil wells have been, and continue to be, drilled in many locations throughout the US. The following graph shows the general increase in crude oil well drilling over the last decade:

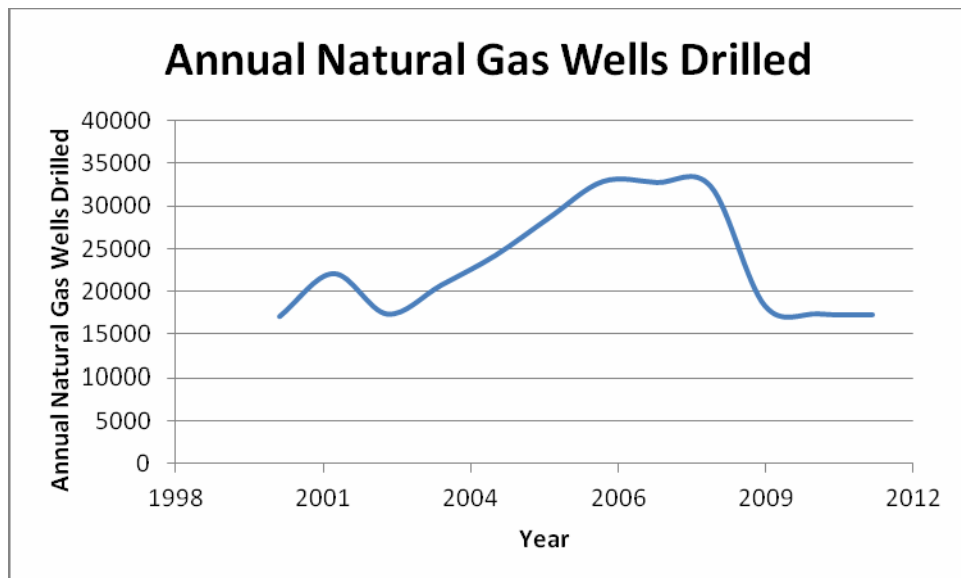


Based on the available data, the U.S. Department of Energy's Energy Information Agency (EIA) noted that in 2009 there were in excess of 960,000 producing oil wells in the US.

Natural gas is produced in 30 of the lower 48 states. Within the OTR, the states of Pennsylvania, New York, and Maryland produce natural gas. Natural gas production has shown an overall increase over the last decade, with an accelerated rate of increase in the last few years. It is interesting to note that during the last few years gas production from conventional (wells drilled vertically into conventional geological formations) gas wells and oil wells has actually decreased. However, that reduction in natural gas production from conventional gas wells and oil wells has been compensated for and surpassed by gas production from shale gas wells and coal bed methane wells. Annual US natural gas production for the last decade is shown in the following graph:

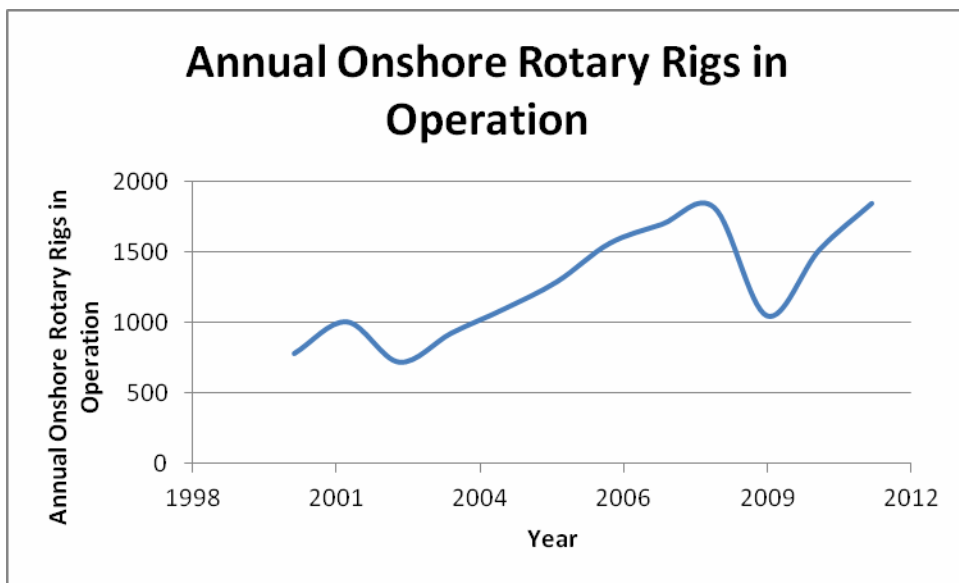


As shown in the following graph, the annual number of natural gas wells being drilled has decreased in the last few years. However, the graph also shows that a significant number of new natural gas wells are continuing to be drilled on an annual basis. While it may seem strange that the natural gas withdrawal has increased but the rate of well drilling has decreased, it should be noted that much of the increase in natural gas production is from shale gas and coal bed methane wells. Shale gas wells and coal bed methane wells are typically deeper and/or longer than conventional gas wells, requiring longer drilling periods, and have, to date, been highly productive.

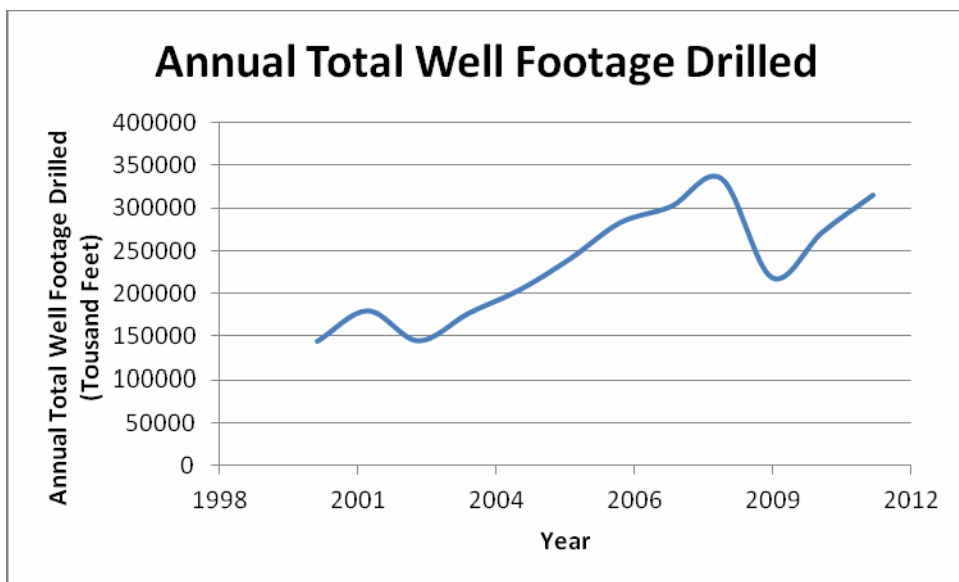


Based on the available data, the EIA noted that in 2009 there were in excess of 1,097,000 producing gas wells in the US.

The combination of increased demand for crude oil and natural gas has caused a general increase in drilling operations. As shown in the following graph, the annual number of well drilling rigs in on-shore operation has generally increased over the last decade.



As would be expected, the general increase in the annual number of well drilling rigs in operation is accompanied by a general increase in the annual total well footage drilled. The following graph shows the total annual well footage drilled over the last decade:



3.0 Oil and Gas Sector NOx Emissions Sources

Within the oil and gas sector, there are many significant NOx emitting sources. Excluding NOx emissions from sources at refineries and gas processing facilities, oil and gas sector NOx emissions sources include the following:

- Diesel and spark ignition reciprocating engines in drilling rig operations (gas and oil sectors).
- Diesel reciprocating engines, spark ignition reciprocating engines, and combustion turbines driving electric generators for power in remote locations and for supporting operation of electric motors (gas and oil sectors).
- Diesel and spark ignition reciprocating engines engine driving hydraulic fracturing pumps, recovery pumps, and water recirculating pumps (oil and gas sectors).
- Gas heating units in well fields working with “wet” gas.
- Oil well heating units.
- Diesel reciprocating engines, spark ignition reciprocating engines, and combustion turbines for well field gas compressors, gas field gathering compressors, and gas pipeline compressors
- Diesel reciprocating engines, spark ignition reciprocating engines, and combustion turbines for wellhead oil pumps, oil field gathering pumps, and oil transportation pipeline pumps.
- Well flairs (oil and gas sectors)

The oil and gas sector NOx emitting processes noted above are further discussed in the following sections.

3.1 Well Drilling and Completion

A well is created by drilling a hole (diameter dependent upon product and expected flow rate) into the earth with a drilling rig that rotates a drill pipe with a drill bit attached. This drilling process is facilitated by the use of a drill rig which contains all the necessary equipment to pump and circulate the drilling fluid, hoist and turn the drill pipe, control down-hole movement, remove cuttings from the drilling fluid, and generate on-site power for these operations.

After drilling and casing the well, it must be 'completed'. Completion is the process in which the well is enabled to produce oil or gas. Often well completion is performed utilizing a specialized rig or platform, enabling the drilling rig to be moved to a new location to drill another well. Well completion may include preparing the last section of the pipe casing in the reservoir to create a flow path from the reservoir into the piping. After a flow path is made, acids and fracturing fluids may be pumped into the well to fracture, clean, or otherwise prepare and stimulate the reservoir rock to optimally produce hydrocarbons into the wellbore.

In some wells, the natural pressure of the subsurface reservoir is high enough for the oil or gas to flow to the surface. However, this is not always the case, especially in depleted fields where the pressures have been lowered by other producing wells, or in low permeability oil reservoirs. Installing smaller diameter tubing may be enough to help the production, but artificial lift methods, such as downhole pumps or surface pumps or compressors, may also be needed. Many new systems have been introduced for improving well completion in recent years that have cut completion costs and improved production, especially in the case of horizontal wells. Some of these well completion activities have also reduced the

amount of gas that is flared by capturing the gas that might otherwise have been flared off and treating and utilizing it as a product.

Sources of NOx emissions from the drilling and completion processes include, but are not limited to, engines driving electric generators that provide electric power supporting the drilling process, engines used to directly power the drilling drive and related pumps and compressors, and flaring of relatively small amount of natural gas as part of well completion. The majority of the engines utilized in this service are diesel reciprocating engines.

Shell operates drilling rigs to support their oil and natural gas development activities. In a presentation, Shell indicated that they have installed SCR on diesel engines that they utilize in drilling rig operations. They indicated that they had been able to achieve greater than 90% reduction in NOx emissions while encountering minimal operational issues.

EIA data indicates that in 2011 there were 1844 on-shore oil and gas drilling rigs in operation in the US, an increase of 330 over 2010 and an increase of 798 over 2009.

EIA data also indicates that there were a combined total of 45,529 oil and gas exploratory and development wells drilled in 2011, an increase of 7,207 wells from those drilled in 2010 and an increase of 12,390 wells from those drilled in 2009. The data indicates that a combined 314,840 thousand feet were drilled in 2011, compared to 271,912 thousand combined feet drilled in 2010 and 218,693 thousand combined feet drilled in 2009.

Because of an overall lack of comprehensive emissions data for NOx sources in the oil and gas sector, and variability due to equipment and site specifics (material being drilled through, well depth, etc), it is difficult to estimate the magnitude of those NOx emissions from well drilling and well completion activities. Some related NOx emissions information was found in a report from the Western Region Air Partnership (WRAP), "An Emissions Inventory of Non-point Oil and Gas Emissions Sources in the Western Region" (presented at the 15th Emission Inventory Conference, New Orleans, May 2006). This report specifically addressed regional emissions from the gas industry, and investigated regional data to estimate NOx emissions factors primarily for natural gas industry operations, with some additional effort to assess oil and methane bed NOx emission factors. The regional data presented in the report indicated a relatively wide range in estimated emission factors, likely due to the site and equipment variability. While the NOx emissions factors presented in the report are based on region specific data, they appear to be realistic values that may be useful in estimating NOx emissions from similar equipment when site or region specific data is not available for other locations. The emissions factors presented in the WRAP report were as follows:

- Drilling: Range of 2.26 tons NOx/well to 9.78 tons NOx/well
- Well Completion: Range of 0.85 tons NOx/well to 1.5 tons NOx/well

While there is no certainty that the above range of emission factors are representative of the range of emission factors on a national basis, the drilling of 45,529 oil and gas wells in 2011 and the use of the

above emissions factors results in a range of NOx emissions of from 141,596 tons to 513,567 tons (drilling and completion related activities only).

An emissions inventory of oil and gas sector emissions for 2005 in Texas (for additional detail see http://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/ei/5820784003FY0701-20090831-ergi-ei_from_old_gas_facilities.pdf) indicated that oil and gas drilling operations accounted for approximately 56.4% of the onshore oil and gas sector NOx emissions. In that same 2005 Texas emissions inventory, oil and gas well completions accounted for approximately 0.2% of the total oil and gas sector NOx emissions.

A more detailed discussion of the engines used to support well drilling and completion activities, and control of NOx emissions from those engines, is provided in later sections of this document.

3.2 Oil Well Pumps

Pumps are often required to raise oil in an oil well from the oil's underground location to the surface. There are several types of pumping devices that are used to provide artificial lift in an oil field. These include: mechanical lift powered by a motor or engine on the surface; hydraulic lift, where oil or water is pumped down into the well to operate a hydraulic pump; electric submersible pump, where a electric motor driven pump at the bottom of the well is driven is supplied electricity from the surface; and gas lift, where natural gas injected into the piping at intervals lightens the weight of the fluid, helping it rise to the surface. All four of these systems offer advantages and disadvantages for specific situations. Mechanical lift is one of the more commonly used oil well pumping devices.

When located near sources of grid supplied electric power, the oil pumps are generally powered by electric motors. In some more remote areas, the oil pumps may still be powered by electric motors, but utilize electricity generated locally using natural gas engine or diesel engine powered electric generators. In other instances, the oil pumps may be driven directly by natural gas fueled engines or diesel engines. The required output rating of the engines would vary depending on the depth of the well, pumping capacity, etc. However, these engines tend to have a relatively small output rating, generally less than 200 hp.

Once the oil is extracted from the well, it is pumped to a storage tank(s) that may be common to multiple supply wells. The oil is then typically transported from the storage tank by truck or pumped out through a pipeline.

Little data was located that could be used to estimate the NOx emissions from oil well pumps. Documentation of previous estimation efforts were equally absent in the data searches. Variables such as well depth and type of prime mover (reciprocating engine, combustion turbine, electric motor) make it very difficult to make any sort of reasonable estimate of the NOx emissions without some detailed inventory and operational information. Because of the lack of data and/or guidance information, no estimates were made of the potential NOx emissions from oil well pumping activities. However, the NOx emissions from engines used to power the oil pumps are generically addressed in later sections of this document.

3.3 Oil Pipeline Pumps

Crude oil is often transported from field gathering locations to downstream locations through pipelines. Industry data indicated that in 2008, pipelines accounted for 71% of all petroleum transportation, up from 67% in 2007. The data indicates that it is estimated that in the US there is in excess of 55,000 miles of crude oil trunk lines connecting regional markets, and estimated that there is from 30,000 miles to 40,000 miles of small crude oil gathering pipelines. Pipelines are also utilized for transportation of refined petroleum products, and industry data estimates indicate that there are approximately 95,000 miles of refined products pipelines in the US.

Pumps are generally required to pump the oil through the pipelines, with pumps generally located at the originating field gathering location and at 20 to 100 mile intervals along the pipeline, depending upon pipeline design, pipeline path geography, and flow requirements. These oil pumps are often driven by electric motors, but some may utilize diesel engines, natural gas fueled reciprocating engines, or combustion turbines to power the pumps when warranted. Little data could be found documenting the size and makeup of the population of oil pipeline pump prime movers.

Little data was located that could be used to estimate the NOx emissions from oil pipeline pumps. Documentation of previous estimation efforts were equally absent in the data searches. Because of the lack of data and/or guidance information, no estimates were made of the potential NOx emissions from oil pipeline pumping activities. However, the NOx emissions from engines used to power the oil pumps are generically addressed in later sections of this document.

3.4 Coal Bed Methane Pumps

In order to facilitate gas extraction from coal bed methane wells, it is often necessary to pump out large amounts of water to reduce the pressure in the coal bed and thereby facilitate methane desorption from the coal. Desorption from the coal allows the methane to be extracted and transported to gathering pipelines. Industry information indicates that the water pumping may occur throughout the useful life of the coal bed methane well, but will tend to experience a reduction with “age” of the well or well field. Coal bed methane pumps are sometimes powered by electric motors, but are typically powered by diesel engines or spark ignited reciprocating engines.

Because of an overall lack of comprehensive emissions data for NOx sources in the oil and gas sector, and variability due to equipment and site specifics, it is difficult to estimate the magnitude of NOx emissions from coal bed methane pumping. Some related NOx emissions information was found in a report from the Western Region Air Partnership (WRAP), “An Emissions Inventory of Non-point Oil and Gas Emissions Sources in the Western Region” (presented at the 15th Emission Inventory Conference, New Orleans, May 2006). This report specifically addressed regional emissions from the gas industry, and investigated regional data to estimate NOx emissions factors that included coal bed methane pumping NOx emission factors. The regional data presented in the report indicated a relatively wide range in estimated emission factors, likely due to the site and equipment variability. While the NOx emissions factors presented in the report are based on region specific data, they appear to be realistic values that may be useful in estimating NOx emissions from similar equipment when site or region

specific data is not available for other locations. The emissions factors presented in the WRAP report for coal bed methane pumps ranged from 0.06 ton/year/well to 0.60 ton/year/well.

NOx emissions from engines used to power the coal bed methane pumps are generically addressed in later sections of this document.

3.5 Oil Well Heaters

Some oil wells require heating of the crude oil, as the crude oil reaching the surface of a well may contain varying amounts of impurities. The well heaters are used to heat crude oil to separate water, solids such as paraffin, and natural gas from the crude oil. Heat from combustion in the heater's firebox heats the crude oil and helps water droplets and solids settle out so that they can be drained out of the bottom of the heater. The heating of the crude oil also facilitates the separation of natural gas from the crude oil, allowing the gas to rise and be piped off from the top of the heater. The oil is then drawn off for pumping to a pipeline or storage tanks.

Because of an overall lack of comprehensive emissions data for NOx sources in the oil and gas sector, and variability due to equipment and site specifics, it is difficult to estimate the magnitude of NOx emissions from oil well heaters. Some related NOx emissions information was found in a report from the Western Region Air Partnership (WRAP), "An Emissions Inventory of Non-point Oil and Gas Emissions Sources in the Western Region" (presented at the 15th Emission Inventory Conference, New Orleans, May 2006). This report specifically addressed regional emissions from the oil and gas industry, and investigated regional data to estimate NOx emissions factors that included oil well heater NOx emission factors. While the NOx emissions factors presented in the report are based on region specific data, they appear to be realistic values that may be useful in estimating NOx emissions from similar equipment when site or region specific data is not available for other locations. The average NOx emissions factor presented in the WRAP report for oil well heaters is 0.005 lb NOx/barrel produced.

Because of the small size of most oil well heater burners, there may be few commercially available combustion or post-combustion technologies commercially available for NOx reduction.

3.6 Gas Well Heaters

Due to varying amounts of condensates and moisture in the gas coming to the surface, some natural gas wells require treatment near the well head. Heating is often part of this "cleanup" process, generally utilizing natural gas fired heating units. The heating of the natural gas is sometimes required to ensure that the temperature of the natural gas does not drop too low where it could facilitate the formation of a hydrate with any water vapor in the gas stream. Natural gas hydrates are crystalline ice-like solids or semi-solids that can impede the passage of natural gas through valves and pipes.

Because of an overall lack of comprehensive emissions data for NOx sources in the oil and gas sector, and variability due to equipment and site specifics, it is difficult to estimate the magnitude of NOx

emissions from gas well heaters. Some related NOx emissions information was found in a report from the Western Region Air Partnership (WRAP), "An Emissions Inventory of Non-point Oil and Gas Emissions Sources in the Western Region" (presented at the 15th Emission Inventory Conference, New Orleans, May 2006). This report specifically addressed regional emissions from the oil and gas industry, and investigated regional data to estimate NOx emissions factors that included gas well heater NOx emission factors. While the NOx emissions factors presented in the report are based on region specific data, they appear to be realistic values that may be useful in estimating NOx emissions from similar equipment when site or region specific data is not available for other locations. The average NOx emissions factor presented in the WRAP report for gas well heaters is 1,752 lb NOx/well/year.

An emissions inventory of oil and gas sector emissions for 2005 in Texas indicated that gas well heaters accounted for approximately 0.5% of the onshore oil and gas sector NOx emissions.

Because of the small size of most gas well heater burners, there may be few commercially available combustion or post-combustion technologies commercially available for NOx reduction from these devices.

3.7 Natural Gas Compressors

The natural gas system in the continental United States is a complex network consisting of equipment and pipelines to gather natural gas from wellheads, transport the raw natural gas to processing facilities as required, transporting the natural gas from processing facilities across potentially large distances to storage facilities and distribution systems, and supplying natural gas to distribution systems that provide the natural gas to the end users.

Compressors are utilized in natural gas fields to boost natural gas wellhead pressure so that the natural gas may be injected into the gathering pipelines to transport it to processing facilities and/or inject the natural gas into the transport pipelines. Compressors are utilized in the transportation network to keep the pipelines pressurized and achieve the desired flow of natural gas. Compressors are also utilized at storage facilities to inject the natural gas into storage and to extract the natural gas from storage and re-inject it back into the transportation or distribution pipelines. Compressors are also sometimes utilized in distribution systems to ensure adequate flow and pressure to the natural gas end users. Most natural gas compressor facilities are normally unmanned, and many are operated from remote facilities to start/stop/modulate output to meet the demands of the associated pipeline systems.

Many natural gas wells require the use of compressors to facilitate extracting the natural gas from the well, boosting the pressure for injecting the natural gas into the field gathering pipeline system, and transporting the natural gas to and from any required field processing facility. Typically, reciprocating engines fueled by raw natural gas are utilized in this service, but other prime movers such as natural gas fueled combustion turbines or electric motors may be utilized in some circumstances. Industry information indicates that compressors utilized in this service tend to run with a relatively constant capacity factor throughout any given calendar year.

Industry literature indicates that the number and size of the compressors utilized in wellhead/gathering systems varies greatly as a result of differences in needed flow capability and pressure boost

requirements. The industry information indicates that utilized compressors can range from portable compressor units with 5 HP prime movers to units that have prime mover ratings in excess of 1500 HP. Natural gas fueled reciprocating engines and combustion turbines, along with electric motors, are commonly utilized in this service. Some locations may be remote relative to sources of off-site electric power, prohibiting the use of electric motors for driving gas compressors unless local electric generation is also provided.

Some natural gas gathering systems include a well field processing facility, which performs such functions as removing impurities like water, carbon dioxide or sulfur that might corrode a pipeline, or inert gases, such as helium, that would reduce the energy value of the gas. These well field processing plants also can remove small quantities of propane and butane. These gases may be used for chemical feedstocks and other applications. Compressors in this service may be utilized to transport natural gas from the wellheads to the well field processing facility, and then from the well field processing facility to the main pipeline network.

Because of the relatively small size of some (but certainly not all) of the combustion engines utilized in natural gas field gathering applications, the available data concerning these units is more limited than that available for the generally higher output mainline compressor prime movers. Industry information indicates that some gas compressor engines used in this service are part of a skid mounted assembly, allowing the compressor to be moved with relative ease and thereby providing additional flexibility in meeting the changing demand associated with removing natural gas from any given well or well field. Industry information also indicates that many of the natural gas compressor prime movers used in this service are leased units.

An emissions inventory of oil and gas sector emissions for 2005 in Texas indicated that natural gas compressors of all kinds collectively accounted for approximately 42.9% of the onshore oil and gas sector NOx emissions.

There was a study performed in 2005 to support an investigation of natural gas field gathering engines in Eastern Texas that might provide some more insight into the potential diversity of engines utilized in the natural gas field gathering service. One of the goals of the Texas study was to get a more firm estimate of the inventory of compressors in use in the area in question. That study indicated that there were a number of engine manufacturers represented in the investigation area, along with a significant number of different engine models among the manufactures. The study was able to determine the age for only a very small portion of the engines in the study, but for that group the engine age ranged from 2 years to 25 years old. The output ratings of the engines in the study ranged from 26 HP to 1478 HP, with the majority rated between 50 HP and 200 HP. Some engines were owned by the gas/collection company, but the majority of the engines were leased units. The Texas report indicates that for this particular group of engines, there was little "seasonality" to their operating schedule, but that they seldom ran at full load (generally between 10% and 70% capacity). In the portion of the region covered in the Texas study that were non-attainment areas, the majority of the engines were found to be rich burn engines, with most required to have NSCR NOx emissions controls installed. The report indicates that the engines in the non-attainment areas not requiring NOx emissions controls were primarily 2-stroke engines, engines under 50 HP, and 4-stroke lean burn engines.

Mainline natural gas transmissions pipeline systems utilize compressors at gas compressor stations to maintain system flow and overcome pressure losses due to the movement of the natural gas through the natural gas pipeline system. These compressor stations are typically located at 40 mile to 100 mile

intervals along the transmission pipeline, as required by the particular pipeline section duty, to maintain the required flow and pressure. These mainline natural gas compressor facilities will often include multiple gas compressors to add flexibility and reliability in meeting the variable natural gas flow demand. Prime movers for these mainline compressors are typically natural gas fired reciprocating engines and combustion turbines, although there are also a number of electric motor driven gas compressors. In some instances, combustion compressor prime movers and electric motor compressor prime movers are located in the same compressor facilities. The horsepower ratings of the individual combustion compressor prime movers range from less than 300 hp to 15,000 hp and more.

For many mainline natural gas compressor stations, industry data indicated that the gas compressor stations have compressors in operation 24 hrs/day and 365 days/year, although not all compressors may be operating or may not be operating at high capacity. The industry data indicates that on average a compressor unit will tend to experience an annual average capacity factor of approximately 40%. For many mainline natural gas compressor facilities, reciprocating engines are preferred for their ability to adjust their output to meet the pipeline demand. Compressor loading will tend to increase during periods of high natural gas demand, such as cold periods with high heating fuel demand or high electric demand days in the Northeast when natural gas fired electric generation is a significant consumer of natural gas.

EIA data indicates that in 2006 there were 1201 natural gas mainline compressor stations in the US, with a combined installed horsepower combined rating in excess of 16.8 million horsepower. The Federal Energy Regulatory Commission (FERC), the approval authority for interstate pipelines projects (including compressor facilities), has records that show that between 2007 through 2010, FERC had approved new compressor facilities or upgrades to existing compressor facilities that are expected to result in the addition of approximately 2.6 million horsepower of compression capability.

Many of the installed reciprocating engines driving mainline natural gas compressors are in excess of 40 years old and therefore pre-date any applicable modern original equipment manufacturer (OEM) installed NO_x emissions controls and any otherwise applicable NSPS NO_x controls. Little information was readily identifiable regarding the number of these units that may have undergone any NO_x emissions reduction modifications as a result of federal or state NO_x reduction retrofit requirements and regulations subsequent to the initial unit installation.

In a document titled "ERLE Cost Study of the Retrofit Legacy Pipeline Engines to Satisfy ½ g/BHP-HR NO_x", dated 5/21/2009, prepared by a technical group for the Pipeline Research Council International, it was stated that a gas industry database of compressor engines identified that there were approximately 5,600 engines on the natural gas pipeline system with a collective rating of approximately 9,150,000 horsepower. The document further indicates that of the engine population, approximately 80% of the rated output was represented by purpose designed low speed two stroke and four stroke integral engines and diesel-derived medium speed engines converted to spark ignition by the engine's original manufacturer. Of the engines represented in the 80% figure, approximately 78% of the engines were two stroke lean burn engines, approximately 14% were four stroke lean burn engines, and 8% of the engines were four stroke rich burn engines. That same population, on a rated horsepower basis, was made up of approximately 80% two stroke lean burn, approximately 15% four stroke lean burn, and approximately 5% four stroke rich burn.

4.0 Oil and Gas Sector Fuel Fired Prime Movers

Data indicates that with the exception of refineries and central natural gas processing plants, the largest collective sources of NOx emissions from the oil and gas sector are reciprocating engines and combustion turbines. These reciprocating engines and combustion turbines are used to power drilling operations, drive various pumping operations, drive oil well pumps and pipeline pumps, and drive well head and pipeline natural gas compressors. Further discussion of these NOx emissions sources and potential NOx controls follow.

4.1 Reciprocating Engines - Two Stroke Lean Burn Spark Ignition Engines

In a reciprocating engine, combustion of a compressed fuel-air mixture is used to drive pistons in one or more cylinders, with the linear piston motion converted to rotary motion with a crankshaft. The rotary motion developed by the reciprocating engine may then be utilized to drive natural gas compressors, pumps, mechanical drives, or other rotary loads. Spark ignition engines use a spark (across a spark plug) to ignite the compressed fuel-air mixture to create the motive force.

Two-stroke engines complete the power cycle in a single engine revolution compared to 2 revolutions for 4-stroke engines. With the 2-stroke engine, the air/fuel charge is injected with the piston near the bottom of the power stroke. The ports or valves are all covered or closed, and the piston moves to the top of the cylinder compressing the charge. Following ignition and combustion, the power stroke starts with the downward movement of the piston. Exhaust ports or valves are then uncovered to remove the combustion products, and a new air/fuel charge is ingested. Two-stroke engines may be turbocharged using an exhaust-powered turbine to pressurize the charge for injection into the cylinder. Non-turbocharged engines may be either blower scavenged or piston scavenged to improve removal of combustion products. The air and fuel are mixed inside the power cylinder and fired by either a spark plug or pre-combustion chamber.

Two stroke engines generally are set to operate with a lean mixture to minimize combustion temperatures, and the fuel lean combustion mixtures tend to produce lower combustion temperatures and therefore lower NOx emissions. Some lean burn engines can be modified to operate with very fuel lean mixtures, further reducing NOx emissions, up to the point where engine miss-fire becomes a problem. Some of the combustion improvements discussed below (high energy ignition, pre-chamber combustion, and improved fuel mixing) facilitate the use of very fuel lean mixtures before engine miss-fires are encountered.

There are many 2-stroke spark ignition reciprocating engines utilized in the oil and gas sector, representing a number of different manufacturers, model numbers, and a wide range of engine output ratings.

4.1.1 Two Stroke Lean Burn Spark Ignition Reciprocating Engine NOx Controls

Industry literature indicates that there are a number of methodologies that are commercially available to help control NOx emissions from two-stroke lean burn spark ignition reciprocating engines (2SLB), most of which are related to efforts to acceptably operate with very lean air/fuel mixtures. While most of the technologies are generically applicable to most of the existing two-stroke lean burn engines,

application on any specific make/model of engine may present unique circumstances that may affect the effectiveness of the control and the cost of installation on that particular engine.

When an engine's air/fuel mixture is leaned to achieve NOx emissions reductions, the amount of spark required from the ignition system to start combustion is increased. High energy ignition systems are applicable to most lean burn engines that are not already equipped with such a system. The high energy ignition system is generally a conventional open-chamber system with the spark plug (or plugs) generally located with the spark plug protruding from the bottom of the combustion cylinder head into the combustion chamber. High energy ignition systems allow more energy to be delivered to the spark plug(s) with a larger gap, thereby increasing the spark energy delivered to the air/fuel mixture and ensuring proper ignition. High energy ignition systems may be digitally controlled systems that use crankshaft referenced angle encoders to deliver precise, high energy ignition sparks. These high energy ignition systems may have the capability to generate multiple, successive sparks during combustion to ensure proper air/fuel light-off. Modern high energy ignition systems tend to reduce miss-fires and engine detonation, and provide a more stable combustion over an engine's entire operating range. Industry information indicates that a slight NOx emissions reduction, approximately 10%, can be achieved through application of a high energy ignition system on an engine that does not have an existing high energy ignition system.

Another methodology for controlling NOx emissions is by improving the combustion air flow characteristics of the engine. Increasing the air flow tends to produce a leaner air/fuel mixture, reducing the peak combustion temperature which tends to reduce NOx emissions. For some engine designs, this may be accomplished by varying the engine load or increasing the engine speed (if within the manufacturer's limits). The air flow of many engines can be increased by converting non-turbocharged engines to incorporate a turbocharger system, modifying or upgrading existing turbocharger systems on engines already incorporating turbochargers, or other unit-specific means to supply combustion air or scavenge the cylinder of combustion products. Turbocharger additions or upgrades often also require upgrades to the rest of the air intake and exhaust systems to accommodate and optimize the new or upgraded turbochargers. Additionally, a turbocharger installation or upgrade may be optimized through the use of intake/combustion air cooling systems. Industry information indicates that, depending upon the degree of upgrade, NOx emissions reductions of up to 75% may be expected for the addition of properly engineered turbocharger systems with intake /combustion air cooling.

Enhanced air fuel mixing technologies are another method of achieving NOx emissions reductions. The design of some two-stroke engines exhibit problems with the ability to thoroughly mix combustion air and fuel. For these engines, the combustion air and fuel may not be introduced for mixing until each has entered the combustion cylinder. The combustion air and fuel mix as the fuel is "sprayed" into the combustion air already in the cylinder. For some engine designs, the air and fuel mixing results in a non-homogeneous mixture that can cause a sporadic and unstable burning process as the flame burns through the cylinder filled with different regions of differing air/fuel mixtures. To improve the mixing process, the fuel supply system and components can be converted to utilize higher fuel injection pressures that force a more rapid and turbulent interaction between the combustion air and fuel and result in a more homogeneous mixture. Industry information indicates that increasing the pressure at which the fuel is injected, and directing the dispersion of the fuel during injection, can significantly reduce emissions and fuel consumption. Industry information indicates that relative to an older low pressure fuel injection system, a well engineered high pressure fuel injection system may be able to facilitate NOx emissions reductions of up to 90% in some engines.

As mentioned above, leaner air/fuel ratios have a tendency to help reduce NOx emissions. However, as the air/fuel ratio is further leaned to attain lower NOx emission rates, the extremely lean air/fuel mixtures become more difficult, if not impossible, to ignite using a standard open-chamber spark plug ignition system. In these cases, a combustion pre-chamber (typically less than 10 percent of the volume of the main chamber) may be installed in the power cylinder head and fitted with a conventional spark plug in the pre-chamber. The fuel supply system is modified to inject fuel into the pre-chamber as well as the main power chamber. During the intake process, the pre-chamber is charged with a richer air/fuel mixture than the main combustion chamber. This richer pre-chamber combustion mixture is more easily ignited by the sparkplug. As the pre-chamber combustion mixture burns, the pressure of the combustion pushes the burning mixture into the main combustion chamber, igniting the main combustion chamber's lean air/fuel mixture. Industry information indicates that the use of ignition pre-chambers may facilitate NOx reductions capabilities of up to 90% in some engines.

Modern electronic engine controls also may be utilized to facilitate the NOx reduction benefits of the above modifications. This is especially true for varying engine load or speed conditions, varying ambient conditions, or startup/shutdown conditions. Some of these devices are air/fuel ratio controllers. Some of these air/fuel ratio controllers utilize mathematical models to monitor certain engine parameters and atmospheric conditions to determine the correct air/fuel mixture for the operating conditions. By tracking and maintaining the "optimal" air/fuel mixture, the engine runs clean and more efficiently. In this way, the engine is more capable of maintaining NOx emissions compliance even with changing operating conditions and ambient condition changes.

Selective catalytic reduction (SCR) is a post-combustion NOx control that utilizes a catalyst and a reducing agent to reduce the concentration of NOx in the exiting combustion gasses. The reagent, typically ammonia or urea, is injected into the exhaust stream of the engine. Once in the exhaust, the ammonia (or urea that decomposes to produce ammonia in the exhaust stream) that passes over a catalyst to help convert the NOx, hydrocarbons, and CO into water, nitrogen and CO₂. Catalyst selection is somewhat based on the expected temperature range of the engine exhaust, and is sized to achieve the desired amount of NOx reduction. The reagent injection system is comprised of a storage tank, reagent injector(s), reagent pump, pressure regulator and electronic controls to accurately meter the quantity of reagent injected as a function of engine load, speed, temperature and NOx emissions. Industry information indicates that the use of SCR for NOx control may facilitate NOx reductions of up to 95%.

2-Stroke Lean Burn Spark Ignition Engine

<u>NOx Control Retrofit Technology</u>	<u>Potential NOx Reduction</u>
High Energy Ignition System	10%
Intake Air Upgrade (turbocharger, etc)	75%
Improved Mixing (high pressure fuel injection)	90%
Pre-Combustion Chamber Ignition System	90%
SCR Catalyst	50% - 95%

4.1.2 Example Existing Rules and Regulations – 2SLB

California's South Coast Air Quality Management District (SCAQMD) has established Rule 1110.2, Emissions from Gaseous and Liquid Fueled Engines, the latest revision of the rule dated July 2010. Rule 1110.2 regulates NOx emissions from new and existing stationary spark or compression ignition internal combustion engines with a nameplate rating of 50 hp or greater. (This rule, 1110.2, may be accessed from <http://aqmd.gov/rules/download.html>)

NOx emission limits noted in SCAQMD Rule 1110.2 applicable to existing stationary spark and compression ignition engines include:

Nameplate - Bhp $\geq$ 500	36 ppmvd NOx (<i>approximately 0.5 g/bhp-hr</i>)
Nameplate - Bhp<500	45 ppmvd NOx (<i>approximately 0.6 g/bhp-hr</i>)
Effective July 1, 2010	
Nameplate - Bhp $\geq$ 500	11 ppmvd NOx (<i>approximately 0.15 g/bhp-hr</i>)
Nameplate - Bhp<500	45 ppmvd NOx (<i>approximately 0.6 g/bhp-hr</i>)
Effective July 1, 2011	
Nameplate - All	11 ppmvd NOx (<i>approximately 0.15 g/bhp-hr</i>)

(Note that SCAQMD Rule 1110.2 contains exemptions for units that operate less than 500 hrs/yr or burn less than 100 MMBTU/yr.) (Note that the rule makes no distinction for rich burn, lean burn, etc stationary engines.)

California's San Joaquin Valley Air Pollution Control District's Rule 4702, Internal Combustion Engines, amended August 18, 2011, regulates NOx emissions from stationary spark and compression ignition engines with nameplate ratings of 25 hp and greater. (This rule may be viewed at <http://www.arb.ca.gov/DRDB/SJU/CURHTML/R4702.PDF>)

The NOx emissions limits noted in the San Joaquin Valley Air Pollution Control District's Rule 4702 for lean burn engines with nameplate ratings of greater than 50 hp and not used for agricultural operations include:

Two-stroke lean burn, gas fueled, < 100hp	75 ppmvd NOx
Lean burn limited use	65 ppmvd NOx
Lean burn used for gas compression	65 ppmvd NOx
Lean burn – all others	11 ppmvd NOx

(Note that the San Joaquin Valley Air Pollution Control District's Rule 4702 definition of limited use requires the engine have a permit restricting the engine's operation to no more than 4000 hrs/yr.)

The state of Colorado's Air Quality Control Commission has established NOx emissions limitations for stationary internal combustion reciprocating engines in its Regulation 7, Control of Ozone Via Ozone Precursors (Emissions of Volatile Organic Compounds and Nitrogen Oxides). Colorado's Regulation 7 has no NOx emissions limitations applicable to lean burn engines.

However, Colorado's Regulation 7 does include NOx emissions limitations applicable to lean burn engines that are new, modified, or relocated stationary natural gas fueled reciprocating internal combustion engines, as follows:

<u>Engine Nameplate</u>	<u>Manufacture Date</u>	<u>NOx Emissions Limit</u>
Nameplate-100≤Bhp<500	Effective January 1, 2008	2 g/bhp-hr
	Effective January 1, 2011	1 g/bhp-hr
Nameplate Bhp≥500	Effective July 1, 2007	2 g/bhp-hr
	Effective July 1, 2010	1 g/bhp-hr

(This Colorado rule may be viewed at <http://www.cdphe.state.co.us/regulations/airregs/5CCR1001-9.pdf>)

The Texas Commission on Environmental Quality revised its permit by rule (revision date February 17, 2012) for the oil and gas industry sources in Texas, §106.352 Oil and Gas Handling and Production Facilities. The Texas rule provides NOx emissions limitations for the various types of oil and gas sector sources, including NOx emissions limitations for 2-stroke lean burn spark ignition engines. The relevant emissions limitations in the rule include the following:

<u>Engine Type</u>	<u>Manufacture Date</u>	<u>NOx Emissions Limit</u>
Two stroke, lean burn SI– BHP≥ 500	Mfg before 9/23/1982	8g/bhp-hr
	Mfg before 6/18/92 & BHP<825	8g/bhp-hr
	9/23/1982≤Mfg<6/18/1992&BHP>825	5g/bhp-hr
	6/18/1992≤Mfg<6/1/2010	2g/bhp-hr
	Mfg on or after 6/1/2010	(exc 5 g/bhp-hr at reduced speed and torque 80%<>100%) 1/g/bhp-hr

(This Texas rule can be reviewed at:

<http://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/og-easy-2012.pdf>).

Additionally, Texas Administrative Code, Combustion Control at Major Industrial, Commercial, and Institutional Sources in Ozone Non-Attainment Areas, Beaumont-Port Arthur Ozone Non Attainment Area Major Sources, Rule §117.105, Emission Specifications for Reasonably Available Control Technology (RACT), provides NOx emissions limitations for natural gas fueled lean burn spark ignition reciprocating engines as follows:

Gas Fueled Lean Burn SI Engine ≥ 300 bhp	3.0 g/bhp-hr
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Pennsylvania has recently proposed a revision to its General Permit for Natural Gas Production and Processing Facilities (GP-5). The proposed GP-5 will apply to all spark ignition internal combustion engines and other air contamination sources at natural gas production and processing facilities. In the proposed GP-5, existing rich and lean burn engines with a nameplate rating of less than or equal to 100

horsepower, but less than 1500 horsepower, will be required to continue to meet the existing GP-5 NOx emissions limit of 2 g/bhp-hr. When the currently proposed GP-5 becomes effective, new and reconstructed engines will be required to meet the following NOx emissions limits:

<u>Configuration</u>	<u>NOx Limit</u>
New and reconfigured Lean Burn Engine ≤ 100 hp	2 g/bhp-hr
New and reconfigured Lean Burn Engine $100 < \text{hp} \leq 637$	1 g/bhp-hr
New and reconfigured Lean Burn Engine > 637 hp	0.5 g/bhp-hr

The USEPA established NOx emissions limitations for natural gas fueled lean burn spark ignition engines in 40 CFR Part 60, Subpart JJJJ (NSPS) (1/18/08 73 FR 3567). The applicable NOx emissions limits for lean burn natural gas-fueled, spark ignition engines are as follows:

<u>Engine Type</u>	<u>Output Rating</u>	<u>Manufacture Date</u>	<u>NOx Emissions Limit</u>
SI Nat. Gas Lean Burn	$500 \geq \text{HP} < 1350$	mfg after 7/1/2008	2.0 g/HP-hr
SI Nat. Gas Lean Burn	$500 \geq \text{HP} < 1350$	mfg after 7/1/2010	1.0 g/HP-hr

4.1.3 Discussion of NOx Reduction Capability – Combustion Modifications

With regard to combustion related NOx reduction retrofits for 2-stroke lean natural gas fueled spark ignition engines, the literature suggests that there are often significant differences in design characteristics between 2SLB engine manufacturers' designs such that applicability and effectiveness of generic NOx combustion controls is highly variable. The literature suggests that this is sometimes due to the air/fuel mixing characteristics and patterns in the engine cylinders that were employed by the manufacturer in the design of the particular engine model. This would indicate that there is also the likelihood of differences between a given manufacturer's engine models and vintage that could affect the applicability and effectiveness of a given NOx control combustion control technology. For some of the more popular or numerous makes and models, the original manufacturer or an aftermarket vendor may offer effective "off-the-shelf" NOx reduction retrofit packages that help reduce the cost of NOx reduction for those makes and model engines. For other engines, only limited support may be available which could require custom design, installation, and tuning of NOx controls that would tend to increase the cost of the NOx emissions reduction project and possibly impact the overall effectiveness of the project.

Other characteristics may also affect the reduction effectiveness, and the cost effectiveness, of a NOx emissions reduction project on any particular engine, such as frequency of startups and shutdowns, operational loading characteristics, location, (altitude, seasonal variations), etc. Variability also potentially exists from installation to installation due to equipment clearances, etc.

The industry literature suggests that in some cases combustion related modifications/upgrades may also offer the possibility of improving the 2-stroke lean burn reciprocating engine's efficiency and range of operation.

There are a number of manufacturers and suppliers that provide components, systems, and services to support combustion related NOx emission reductions from two stroke lean burn engines. Some of these organizations include the following:

- Windrock offers an autobalance system that automatically balances the cylinder-to-cylinder combustion in multi-cylinder slow speed integral engines such as Cooper-Bessemer, Clark/Dresser, Ingersoll-Rand, Worthington, and other two- or four-stroke engines with individual cylinder fuel adjustment valves. The system constantly adjusts fuel flow to each power cylinder in order to maintain peak firing pressures to $\pm 5\%$ of engine average during differing ambient conditions, varying speeds and changing loads. Eliminating unbalanced operation across all operating conditions enables the engine to run with the minimum possible NOx and facilitates the positive results of other NOx reduction modifications. For additional information see: http://www.cookcompression.com/files/comm_id_68/GMJJournal_Q32009_AutoBalance.pdf
- Dresser-Rand, a reciprocating engine OEM, offers a retrofit NOx emission technology system for a number of engine models. While somewhat dependent upon the specific model, the retrofit NOx emission reduction system may include a screw-in combustion pre-chamber high energy ignition system, earlier fuel injection timing and directional fuel injection for improved air/fuel mixing, improved controls for more precise fuel injection and engine timing, and improved air flow to further lean the mixture when applicable. Dresser-Rand also offers more extensive NOx reduction systems for retrofit, which depending upon engine model may include new cylinder heads with pre-combustion chambers, new main fuel gas injection valves, high efficiency turbochargers, larger turbocharger combustion air intercooler with plenums, new fuel management system, air/fuel ratio controller, new spark controller, new cams and/or camshaft on four-stroke engines, and a high-energy ignition system. Industry literature indicates that Dresser-Rand offers related retrofit NOx reduction controls for TVC, TCVA, TCVD, TLA, TLAD, LA, HLA, HLA/T, BA, HBA, HBA/T, RA, HRA, and HRA/T two stroke engines (Clark, Dresser-Clark). The literature also indicates that NOx emission guarantees of between 2.5 g/bhp-hr and 3.0 g/bhp-hr have been provided with these NOx reduction technologies, and that those guarantees have been consistently met or improved upon. For additional information see: <http://dresser-rand.com/service/engineeredolutions/revamps/ recip.php> , <http://www.dresser-rand.com/techpapers/tp014.pdf>
- Cameron offers a NOx reduction system for Ajax two stroke lean burn engines. Cameron's exhaust expansion chamber for the Ajax engine features diverging and converging sections of pipe using exhaust pulsations to optimize the scavenging of the power cylinders while providing a substantial increase in fresh air trapped in the cylinder. The results are improved performance and cooler combustion, which reduce the NOx levels up to 60%. For additional information see: (<http://cameronscompressionsystems.blogspot.com/2009/10/ajax-integral-engine-compressors.html>) (http://www.coopercameron.com/images/File/AJAX_brochure-vf2.pdf)

Cameron also offers retrofit NOx reduction systems for many Cooper Bessemer engines. Depending upon the model, the retrofits may include electronic fuel injection, pre-chambers with electronic check valves, and improved intake and exhaust systems. For certain models Cameron may also redesign the cylinder head to allow for leaner combustion and improving combustion stability. For additional information see: <http://cameronscompressionsystems.blogspot.com/2009/10/cooper-bessemer.html>

An internet search identified a couple of documents discussing the results of NOx reduction combustion control projects or studies for two stroke lean burn engines, including some limited cost estimates. The information from this search is discussed below:

- In a 2011 presentation, Available Emission Reduction Technology for Existing Large Bore Slow Speed Two Stroke Engines, Cameron discussed its ability and experience in retrofitting low-NOx combustion modifications for large bore 2-stroke lean burn engines. In the document Cameron discussed a recent (2010) retrofit project that incorporated the use of high pressure fuel injection, turbocharging, pre-combustion chambers, and cylinder head modifications to attain a NOx emissions rate of 0.5 g/bhp-hr with an operating range of 80% for both engine speed and torque output. In this presentation Cameron further provided estimates for the cost of achieving similar NOx emission rates for several makes, models and output ratings of two stroke lean burn engines. The engines identified by Cameron in this estimation ranged from 200hp 6-cylinder engines to 11,000hp 20-cylinder engines. The estimated project costs ranged, depending upon make/model/output, from \$4.3 million per engine to \$1.9 million per engine, or from a low of \$162,500 per cylinder to a high of \$466,667 per cylinder, or from a low of \$245 per rated hp to a high of \$1400 per rated hp. This information shows the variability associated with NOx reduction efforts required for the various makes/models/outputs of the large bore two stroke engines.
- In a document titled "ERLE Cost Study of the Retrofit Legacy Pipeline Engines to Satisfy ½ g/BHP-HR NOx", dated 5/21/2009, prepared by a technical group for the Pipeline Research Council International, the results were discussed of an evaluation of the costs to attain NOx emission rates of 0.5 g/bhp-hr for legacy natural gas fueled 2-stroke lean burn engines used in pipeline compressor service. For the evaluation, three of the most representative make/models of 2-stroke lean burn integral compressor engines (2250 hp Cooper GMVH-10, 2000 hp Clark TLA-6, 2500hp Cooper GMW-10) were selected for evaluation. The evaluation concluded that there were no technology gaps and that each of the three makes/models evaluated were capable of attaining a NOx emissions limitation of 0.5 g/bhp-hr using a combination of improvements and retrofits related to air supply, fuel supply, ignition, electronic controls, and engine monitoring. The document also provided an estimate of the cost range to achieve the 0.5 g/bhp-hr NOx emission rate for each of the subject engines, as follows:

<u>Engine</u>	<u>Output</u>	<u>First Unit Upgrade Cost</u>	<u>Follow On Unit Upgrade Cost</u>
Cooper GMVH-10	2250 hp	\$2,050,000 - \$2,150,000	\$1,850,000 - \$1,950,000
Clark TLA-6	2000 hp	\$2,850,000 - \$2,950,000	\$2,550,000 - \$2,650,000
Cooper GMW-10	2500 hp	\$3,250,000 - \$3,350,000	\$2,950,000 - \$3,050,000

(Source: <http://www.coresymposium.com/2010Core/EngineCostStudy.pdf>)

The information suggests that most 2-stroke lean burn engines would be responsive to combustion and airflow modifications (potentially including installation/upgrade of turbochargers and inter-cooling, pre-chamber ignition or high energy ignition, improved fuel injection control, air/fuel ratio control, etc). All of the mentioned retrofit combustion related NOx controls may not be commercially available for all manufacturers and models of 2-stroke lean burn engines. It appears that the actual achievable NOx emission rate, in terms of g/bhp-hr, would tend to be engine design specific. Additionally, site specific installation issues may be greatly problematic or not cost effective. These engine and site specific issues are not altogether different than issues encountered with other types of emissions reduction technologies and projects. These types of issues can usually be addressed by providing appropriate flexibility in any rulemaking that includes consideration of site specific issues.

The available information suggests that combustion related modifications have the potential to achieve from 60% to 90% reduction in NOx emissions from two stroke lean burn spark ignited reciprocating engines, depending upon the make/model configuration of the engine. This suggests an approximate range of NOx emissions rate of 3.0 g/bhp-hr to 0.5 b/bhp-hr, depending upon the make/model configuration of the engine. The higher rates of NOx emissions reductions, and lower g/bhp-hr rate NOx emissions, are potentially achievable on some of the larger two stroke lean burn engines where NOx reduction systems are available that include layered combustion controls such as improved airflow, improved fuel-air mixing, improved ignition, and upgraded controls. The higher emission rates would tend to be more representative of the two stroke lean burn spark ignited reciprocating engine design and some larger units where layered NOx reduction packages have not been commercialized.

The same information indicates that there is a wide range of estimated costs for installation of combustion related controls with a target NOx emissions rate of 0.5 g/bhp-hr. The estimated range of cost is from \$245 per rated horsepower to \$1475 per rated horsepower. The range in cost appears to be affected both by the make/model/configuration of the engine and the output rating of the engine.

4.1.4 Discussion of NOx Reduction Capability – Post Combustion Modifications

With regards to post-combustion related NOx reduction retrofits for 2-stroke lean burn natural gas fueled spark ignition engines, the literature suggests that selective catalytic reduction (SCR) is technically feasible to achieve significant NOx emission rate reductions from 2SLB engines, but that there are problems that make SCR installation questionable. The first issue is that the 2SLB engine operation is very sensitive to changes in exhaust pressure, which could be problematic with the retrofit of SCR on existing engines. However, this issue can be alleviated for most units through proper design and sizing of airflow and exhaust components.

Some industry information suggests that the two stroke lean burn spark ignition engine's range of exhaust temperature may be too low for proper SCR operation. In a presentation titled "Challenges in Retrofitting Selective Catalytic Reduction (SCR) Systems to Existing Stationary Natural Gas Fired Engines" that was presented at the October 5, 2011 Gas Machinery Conference, it was stated that applying SCR to pipeline engines is not feasible because the exhaust temperatures are below the operating window for SCR or at a level where the SCR effectiveness is reduced, that the exhaust temperature is below the temperature for reliable decomposition of urea into ammonia, and the effectiveness of SCR has not been demonstrated on the slow speed, large bore, low exhaust temperatures typical of gas pipeline engines. For additional information see:

<http://www.gmrc.org/ckfinder/userfiles/files/GMC%20Conf/Final%20Papers/Challenges%20in%20Retrofitting%20SCR%20Systems.pdf>

However, there are a number of organizations that market SCR systems that indicate that their catalysts are capable of effectively operating over a wide range of exhaust gas temperature. Such catalysts would serve to offer considerable flexibility for application to varying makes/models of two stroke lean burn engines, as well as providing flexibility for effective NO_x reduction over a range of operating conditions for those engines.

Another stated issue is that many compressor facilities are unmanned and that SCR installations have not been demonstrated in unmanned facilities. Other industry information indicates that while it may be true that there are currently few SCRs in unmanned facilities, with modern software based controls and supervisory control and data acquisition (SCADA) type communication technologies there does not appear to be any technical barrier to operating the SCR related controls and auxiliaries successfully from a remote location.

Another industry concern that has been stated is that SCRs have not been demonstrated on combustion devices with variable loads. However, SCR manufactures indicate that they offer catalysts that are effective over wide temperature ranges characteristic of a range in engine operating load. Modern controls also have the ability to closely regulate fuel and air flows to ensure combustion gas oxygen and temperature levels at expected levels and to regulate reagent flow, all serving to ensure proper SCR function over a broad range of load.

In a document titled "ERLE Cost Study of the Retrofit Legacy Pipeline Engines to Satisfy ½ g/BHP-HR NO_x", dated 5/21/2009, prepared by a technical group for the Pipeline Research Council International, the results were discussed of an evaluation of the costs to attain NO_x emission rates of 0.5 g/bhp-hr for legacy natural gas fueled 2-stroke lean burn engines used in pipeline compressor service. For the evaluation, three of the most representative make/models of 2-stroke lean burn integral compressor engines (2250 hp Cooper GMVH-10, 2000 hp Clark TLA-6, 2500hp Cooper GMW-10) were selected for evaluation. The evaluation concluded that there were no technology gaps and that each of the three makes/models evaluated were capable of attaining a NO_x emissions limitation of 0.5 g/bhp-hr using a combination of improvements and retrofits related to air supply, fuel supply, ignition, electronic controls, and engine monitoring. The document also briefly discusses using SCR as an alternative to the layered combustion related improvements/retrofits. The document discussed that SCR is a high cost alternative to the combustion related improvements/retrofits, primarily due to the high cost of ongoing reagent consumption. For additional information see:

<http://www.coresymposium.com/2010Core/EngineCostStudy.pdf>

Even though some industry sources indicate that SCR is not a practical or proven NO_x reduction technology for two stroke lean burn engines, there are a number of manufacturer's and suppliers that offer SCR systems that may be used on two stroke lean burn engines. Some of the manufacturer and supplier information is provided below:

- Johnson Matthey markets urea based SCR systems that reduce NO_x emissions from lean burn natural gas fueled engines by 90% or more. Johnson Matthey offers catalysts with a broad effective operating temperature range to achieve NO_x reductions earlier in an engine operating cycle and across a wide engine operating range. For additional information see:
<http://ect.jmcatalysts.com/site.asp?siteid=836&pageid=888&furtherid=946>

- Miratech Corporation offers a SCR based NOx reduction system that is advertised to be applicable to lean burn engines used in natural gas compression applications. Miratech indicates that NOx reductions of up to 99% are achievable with their SCR system. For additional information see: http://www.miratechcorp.com/images/data/attachments/0000/0019/SCR_Systems.pdf
- CleanAir Systems offers a SCR system that they advertise as being applicable to lean burn natural gas fired engines, including those utilized for gas compression. CleanAir indicates that their SCR catalyst allows NOx reduction operation in a wide range of temperatures, from approximately 300 degF to approximately 1000 degF. (CleanAir Systems was acquired by Caterpillar in 2010, and is now called CleanAir Systems, A Caterpillar Company.) Their lean burn engine SCR product is now being referred to as E-Pod SCR. CleanAir indicates that their lean burn engine capable SCR achieves up to 95% reduction in NOx emissions across a wide range of exhaust temperatures. For additional information see: <http://www.cleanairsys.com/products/hybrids/index.htm>

Information from the Manufacturers of Emission Controls Association (MECA) indicated that there have been some limited examples of SCR being retrofit on two stroke lean burn engines as part of demonstration test programs, but that the results of these test programs have never been published. MECA indicated that there have been several demonstrations conducted by independent laboratories where SCR was retrofitted on such two-stroke, lean-burn natural gas spark ignited reciprocating engines that achieved >90% reduction in NOx. It was indicated that SCR retrofits were a challenge on some two stroke lean burn engines because of the relatively low exhaust temperatures on some of the older 2-stroke engines. However, MECA indicated that more modern SCR systems operate over a much broader operating range, and some of MECA's members have formulated catalysts specifically for these large two-stroke engines and demonstrated their effectiveness down to exhaust temperatures as low as 250°C and as high as 550°C. MECA stated that a NOx emissions rate of around 0.5 g/bhp-hr would more closely represent the capability of SCR achieving a 90% reduction in NOx emissions from two stroke lean burn spark ignited reciprocating engines.

It also appears that installation of SCR may be a beneficial NOx control technology on two stroke lean burn spark ignition reciprocating engines that have previously been modified with combustion related controls to moderately reduce the engine's NOx emission rate. The "reduced engine out" NOx emission rate, combined with the NOx control capability of SCR, may achieve NOx emission rates of 0.5 g/bhp-hr or less.

From the available information it appears that SCR systems potentially applicable to two stroke lean burn reciprocating engines are available from several suppliers. It also appears that one of the main drawbacks at this time is that there are no public demonstration projects or completed projects in commercial operation to prove the viability of SCR in this service. As of the preparation of this document, we are unaware of installations of SCR controls in this application.

From the available information it appears that the use of SCR for NOx control does not appear to be technically infeasible generically, but that individual two stroke lean burn reciprocating engine characteristics and installations may be greatly problematic or not cost effective. This "site specific" issue is not altogether any different than other types of emission reduction technologies, and can usually be addressed by providing appropriate flexibility in any rulemaking that includes consideration of site specific issues.

Without the benefit of information from actual installations or comprehensive engineering evaluations, it is difficult to definitively identify a range of NOx emissions reduction possible from installation of SCR on two stroke lean burn spark ignition reciprocating engines. The information from SCR suppliers and MECA suggests that, for two stroke lean burn reciprocating engines, SCR may be capable of achieving approximately 90% reduction in NOx emissions, giving a potential range of NOx emissions rates of 0.5 g/bhp-hr to 1.0 g/bhp-hr.

Likewise, without the benefit of information from actual installations or comprehensive engineering evaluations, it is difficult to provide any range of costs regarding installation of SCR on the variety of two stroke lean burn spark ignited reciprocating engines. However, the “ERLE Cost Study of the Retrofit Legacy Pipeline Engines to Satisfy $\frac{1}{2}$ g/BHP-HR NOx” document provided some capital cost information related to the installation of SCR on two stroke lean burn engines with the intent of approaching a NOx emissions rate of 0.5 g/bhp-hr. (The document points out that some combustion related NOx emission reductions may be required to help the primary SCR NOx control to achieve an overall 0.5 g/bhp-hr NOx emission rate.) For the nominal 2000 hp to 2500 hp two stroke lean burn reciprocating engines evaluated in the ERLE document, the document indicates that capital cost estimates for SCR would be in the range of \$740,000 to \$890,000. The document also estimated annual reagent costs in excess of \$120,000 for these SCR systems.

4.1.5 Two Stroke Lean Burn Spark Ignition Reciprocating Engine NOx Control Summary

Industry information indicates that there are technically feasible, commercially available NOx reduction technologies applicable to natural gas fueled, spark ignited, lean burn reciprocating engines. The information suggests that most of these engines would be responsive to combustion and airflow modifications (potentially including installation/upgrade of turbochargers and inter-cooling, pre-chamber ignition or high energy ignition, improved fuel injection control, air/fuel ratio control, etc). The industry information also indicates that there are technically feasible, commercially available post-combustion (SCR) NOx reduction systems available for use on these same engines. However, some of the combustion related and post combustion NOx controls may not be commercially available for all manufacturers and models of two stroke lean burn spark ignited reciprocating engines.

From the industry information it appears that the actual achievable NOx emission rate, in terms of g/bhp-hr, would tend to be engine design specific. Additionally, site specific installation issues may impact controls installation such that the installations are operationally problematic or not cost effective. These engine design and site specific issues are not altogether different than issues encountered with other types of emissions reduction technologies and projects, and can usually be addressed by providing appropriate flexibility in any rulemaking that includes consideration of site specific issues.

The information therefore seems to support NOx emission rate limits of as low as 0.5 g/bhp-hr for many two-stroke lean burn spark ignition reciprocating engines with a nameplate rating of 250 hp or above, providing that there is consideration of individual engine design and site specific flexibility provisions. For two stroke lean burn engines with nameplate ratings below 250 hp, the available industry information indicates NOx emission rate limits of around 3 g/bhp-hr for some of the existing popular

make/model combinations. Again, this could be addressed with appropriate rule or regulation consideration of individual engine design and site specific flexibility provisions.

Very little information was found regarding the cost of purchase and installation of combustion related and post-combustion NOx controls for two stroke lean burn engines. The following summarizes the limited information:

Type of NOx Control	Engine Size Range (hp)	Estimated Range of NOx	Estimated Range of NOx	NOx Control Estimated Costs (\$)
		Reduction (%)	Emissions Rate (g/bhp-hr)	
Layered Combustion	100 - 250	60 - 90	3 - 0.5	182,000 - 456,000
Layered Combustion	2000 - 2500	90	0.5	2,175,000 - 3,554,000
SCR	2000 - 2500	90	0.5	1,050,000 - 1,210,000

(Note: Estimated control costs are initial capital cost estimates only. Costs are based on information from “ERLE Cost Study of the Retrofit Legacy Pipeline Engines to Satisfy ½ g/BHP-HR NOx” document, adjusted for CPI.)

It should be noted that the range of costs, especially for the combustion related NOx control modifications, is more representative of the diversity of the modifications that might be required to attain the NOx emission rate limits rather than a function of the nameplate rating of the engine. This is due to the fact that some engines may require complete new turbocharger systems with related auxiliaries, while some may require relatively modest modifications to existing induction systems, some may require new precombustion chamber (PCC) combustion ignition systems while others may require only minor improvements, etc. These differences can exist across the range of four stroke lean burn engine nameplate ratings. As discussed earlier, applicability and effectiveness of a given NOx control technology to a particular engine may vary by engine make, model, vintage, location, and operating characteristics.

4.2 Reciprocating Engines - Four Stroke Lean Burn Spark Ignition Engines

In a reciprocating engine, combustion of a compressed fuel-air mixture is used to drive pistons in one or more cylinders, with the linear piston motion converted to rotary motion with a crankshaft. The rotary motion developed by the reciprocating engine may then be utilized to drive natural gas compressors, pumps, mechanical drives, or other rotary loads. Spark ignition engines use a spark (across a spark plug) to ignite the compressed fuel-air mixture to create the motive force.

Four-stroke spark ignition reciprocating engines use a separate engine revolution for the intake/compression stroke and the power/exhaust stroke. Four-stroke engines complete the combustion cycle in two revolutions of the crankshaft. Each of the piston's four strokes has an important function in the engine cycle (intake, compression, power and exhaust). These engines have intake and exhaust valves to introduce combustion air into the cylinder and exhaust combustion gases from the cylinder. Most four-stroke spark ignition reciprocating engines use open-chamber spark plugs to ignite the air/fuel mixture, and can be configured to operate as rich- or lean burn, depending on the air/fuel mixture. These reciprocating engines may be either naturally aspirated, using the suction from the piston to entrain the air charge, or utilize a supercharger or turbocharger to pressurize the inlet air/fuel charge.

Lean-burn four-stroke spark ignition engines usually have a fuel injection system that injects the fuel near the intake valves or in the power head. They use either open-chambered spark plugs or pre-combustion chamber ignition systems to assure ignition of the lean mixture. Lean burn spark ignited reciprocating engines are often fitted with a mechanically driven blower or turbocharger to supply the required combustion air. Lean burn engines have higher oxygen levels in the combustion chamber (and exhaust), which decreases the combustion temperature and thereby reducing the amount of NO_x that is formed during combustion. Because the air-to-fuel ratio is lean with fuel, less fuel is used, which results in decreased combustion temperatures, decreased engine power, and increased engine efficiency relative to a rich burn engine.

Some lean burn four-stroke spark ignited reciprocating engines can be modified to operate with very fuel lean mixtures, further reducing NO_x emissions, up to the point where engine misfire becomes a problem. Combustion improvements such as high energy ignition, pre-chamber combustion, and improved fuel mixing may be incorporated on four-stroke engines to facilitate the use of very fuel lean mixtures before engine misfires are encountered.

There are many four stroke lean burn (4SLB) spark ignition reciprocating engines in service, representing a number of different manufacturers, model numbers, and a range of output ratings.

4.2.1 Four Stroke Lean Burn Spark Ignition Engine NO_x Controls

Industry literature indicates that there are a number of methodologies that are commercially available to help control NO_x emissions from four-stroke lean burn spark ignition reciprocating engines, most of which are related to efforts to acceptably operate with very lean air/fuel mixtures. While most of the technologies are generically applicable to most of the existing four-stroke lean burn reciprocating engines, application on any specific make/model of engine may present unique circumstances that may affect the effectiveness of the control and the cost of installation on that particular engine.

When an engine's air/fuel mixture is leaned to achieve NOx emissions reductions, the amount of spark energy required from the ignition system to start combustion is increased. High energy ignition systems are applicable to most lean burn engines that are not already equipped with such a system. The high energy ignition system is generally a conventional open-chamber system with the spark plug (or plugs) generally located with the spark plug protruding from the bottom of the combustion cylinder head into the combustion chamber. High energy ignition systems allow more energy to be delivered to the spark plug(s) with a larger gap, thereby increasing the spark energy delivered to the air/fuel mixture and ensuring proper ignition. High energy ignition systems may be digitally controlled systems that use crankshaft referenced angle encoders to deliver precise, high energy ignition sparks. These high energy ignition systems may have the capability to generate multiple, successive sparks during combustion to ensure proper air/fuel light- off. Modern high energy ignition systems tend to reduce misfires and engine detonation, and provide a more stable combustion over an engine's entire operating range. Industry information indicates that a slight NOx emissions reduction, approximately 10%, can be achieved through application of a high energy ignition system on an engine that does not have an existing high energy ignition system.

Another methodology for controlling NOx emissions is by improving the combustion air flow characteristics of the engine. Increasing the air flow tends to produce a leaner air/fuel mixture, reducing the peak combustion temperature which tends to reduce NOx emissions. For some engine designs, this may be accomplished by varying the engine load or increasing the engine speed (if within the manufacturer's limits). The air flow of many engines can be increased by converting non-turbocharged engines to incorporate a turbocharger system, modifying or upgrading existing turbocharger systems on engines already incorporating turbochargers, or other unit-specific means to supply combustion air or scavenge the cylinder of combustion products. Turbocharger additions or upgrades often also require upgrades to the rest of the air intake and exhaust systems to accommodate and optimize the new or upgraded turbochargers. Additionally, a turbocharger installation or upgrade may be optimized through the use of intake/combustion air cooling systems. Industry information indicates that, depending upon the degree of upgrade, NOx emissions reductions of up to 75% may be expected for the addition of properly engineered turbocharger systems with intake /combustion air cooling.

Enhanced air-fuel mixing technologies are another method of achieving NOx emissions reductions. The design of some four-stroke engines exhibit problems with the ability to thoroughly mix combustion air and fuel. For these engines, the combustion air and fuel may not be introduced for mixing until each has entered the combustion cylinder. The combustion air and fuel mix as the fuel is "sprayed" into the combustion air already in the cylinder. For some engine designs, the air and fuel mixing results in a non-homogeneous mixture that can cause a sporadic and unstable burning process as the flame burns through the cylinder filled with different regions of differing air/fuel mixtures. To improve the mixing process, the fuel supply system and components can be converted to utilize higher fuel injection pressures that force a more rapid and turbulent interaction between the combustion air and fuel and result in a more homogeneous mixture. Industry information indicates that increasing the pressure at which the fuel is injected, and directing the dispersion of the fuel during injection, can significantly reduce emissions and fuel consumption. Industry information indicates that relative to an older low pressure fuel injection system, a well engineered high pressure fuel injection system may be able to facilitate NOx emissions reductions of up to 90% in some engines.

As mentioned above, leaner air/fuel ratios have a tendency to help reduce NOx emissions. However, as the air/fuel ratio is further leaned to attain lower NOx emission rates, the extremely lean air/fuel

mixtures become more difficult, if not impossible, to ignite using a standard open-chamber spark plug ignition system. In these cases, a combustion pre-chamber (typically less than 10 percent of the volume of the main chamber) may be installed in the power cylinder head and fitted with a conventional spark plug in the pre-chamber. The fuel supply system is modified to inject fuel into the pre-chamber as well as the main power chamber. During the intake process, the pre-chamber is charged with a richer air/fuel mixture than the main chamber. This richer pre-chamber combustion mixture is more easily ignited by the sparkplug. As the pre-chamber combustion mixture burns, the pressure of the combustion pushes the burning mixture into the main power chamber, igniting the main power chamber's lean air/fuel mixture. Industry information indicates that the use of ignition pre-chambers may facilitate NOx reductions capabilities of up to 90% in some four stroke spark ignited reciprocating engines.

Modern electronic engine controls also may be utilized to facilitate the NOx reduction benefits of the above modifications. This is especially true for varying engine load or speed conditions, varying ambient conditions, or startup/shutdown conditions. One type of control device is referred to as an air/fuel ratio controller. Some of these air/fuel ratio controllers utilize mathematical models to monitor certain engine parameters and atmospheric conditions to determine the correct air/fuel mixture for the operating conditions. By tracking and maintaining the "correct" air/fuel mixture, the engine runs clean and more efficiently. In this way, the engine is more capable of maintaining NOx emissions compliance even with changing operating conditions and changes in ambient conditions.

Another potential NOx reduction technology for four-stroke lean burn spark ignited reciprocating engines is the use of exhaust gas recirculation (EGR). EGR systems utilize hardware changes to recirculate engine exhaust gases into the combustion chamber of the engine as an inert substitute for the excess air normally supplied in lean burn reciprocating engine operation. EGR allows the combustion chamber to operate as if it were a rich burn engine and, since no excess oxygen is present in the exhaust, a much less expensive nonselective reduction catalyst (NSCR) can be used when post-combustion NOx controls are needed to meet the most stringent NOx emissions standards. NOx emissions rates from an EGR and NSCR equipped engine can be as low as, or lower than, a lean burn engine equipped with a selective catalytic reduction (SCR) system. Several independent companies have installed retrofit systems on existing natural gas engines and have reported some success in meeting very low emissions requirements during initial and limited field testing. Engine performance and fuel efficiency are reported to be the equivalent of standard lean burn engines yet are still able to utilize NSCR for meeting stringent NOx emissions limitations. This NOx control strategy has yet to achieve widespread acceptance in a retrofit application.

Selective catalytic reduction (SCR) is a post-combustion NOx control that utilizes a catalyst and a reducing agent to reduce the concentration of NOx in the exiting combustion gasses. The reagent, typically ammonia or urea, is injected into the exhaust stream of the engine. Once in the exhaust, the ammonia (or urea that decomposes to produce ammonia in the exhaust stream) passes over a catalyst to help convert the NOx, hydrocarbons, and CO into water, nitrogen and CO₂. Catalyst selection is somewhat based on the expected temperature range of the engine exhaust, and is sized to achieve the desired amount of NOx reduction. The reagent injection system is comprised of a storage tank, reagent injector(s), reagent pump, pressure regulator and electronic controls to accurately meter the quantity of reagent injected as a function of engine load, speed, temperature and NOx emissions. Industry information indicates that the use of SCR for NOx control may facilitate NOx reductions of up to 95%.

4-Stroke Lean Burn Spark Ignition Engine

NOx Control Retrofit Technology

Potential NOx Reduction

High Energy Ignition System	10%
Intake Air Upgrade (turbocharger, etc)	60% - 70%
Improved Mixing (high pressure fuel injection)	90%
Pre-Combustion Chamber Ignition System	90%
SCR Catalyst	50% - 95%

4.2.2 Example Existing Rules and Regulations – 4SLB

California - California's South Coast Air Quality Management District (SCAQMD) has established Rule 1110.2, Emissions from Gaseous and Liquid Fueled Engines, the latest revision of the rule dated July 2010. Rule 1110.2 regulates NOx emissions from new and existing stationary spark or compression ignition internal combustion engines with a nameplate rating of 50 hp or greater. (This rule, 1110.2, may be accessed from <http://aqmd.gov/rules/download.html>)

NOx emission limits noted in SCAQMD Rule 1110.2 applicable to existing stationary spark and compression ignition engines include:

Nameplate - Bhp $\geq$ 500	36 ppmvd NOx (<i>approximately 0.5 g/bhp-hr</i>)
Nameplate - Bhp<500	45 ppmvd NOx (<i>approximately 0.6 g/bhp-hr</i>)
Effective July 1, 2010	
Nameplate - Bhp $\geq$ 500	11 ppmvd NOx (<i>approximately 0.15 g/bhp-hr</i>)
Nameplate - Bhp<500	45 ppmvd NOx (<i>approximately 0.6 g/bhp-hr</i>)
Effective July 1, 2011	
Nameplate - All	11 ppmvd NOx (<i>approximately 0.15 g/bhp-hr</i>)

(Note that SCAQMD Rule 1110.2 contains exemptions for units that operate less than 500 hrs/yr or burn less than 100 MMBTU/yr.) (Note that the rule makes no distinction for rich burn, lean burn, etc stationary engines.)

California – California's San Joaquin Valley Air Pollution Control District's Rule 4702, Internal Combustion Engines, amended August 18, 2011, regulates NOx emissions from stationary spark and compression ignition engines with nameplate ratings of 25 hp and greater. (This rule may be viewed at <http://www.arb.ca.gov/DRDB/SJU/CURHTML/R4702.PDF>)

The NOx emissions limits noted in the San Joaquin Valley Air Pollution Control District's Rule 4702 for lean burn engines with nameplate ratings greater than 50 hp and not used for agricultural operations include:

Two-stroke lean burn, gas fueled, < 100hp	75 ppmvd NOx
Lean burn limited use	65 ppmvd NOx
Lean burn used for gas compression	65 ppmvd NOx
Lean burn – all others	11 ppmvd NOx

(Note that the San Joaquin Valley Air Pollution Control District's Rule 4702 definition of limited use requires the engine have a permit restricting the engine's operation to no more than 4000 hrs/yr.)

Colorado - The state of Colorado's Air Quality Control Commission has established NOx emissions limitations for stationary internal combustion reciprocating engines in its Regulation 7, Control of Ozone Via Ozone Precursors (Emissions of Volatile Organic Compounds and Nitrogen Oxides). Colorado's Regulation 7 has no NOx emissions limitations applicable to existing lean burn engines.

However, Colorado's Regulation 7 does include NOx emissions limitations applicable to lean burn engines that are new, modified, or relocated stationary natural gas fueled reciprocating internal combustion engines, as follows:

<u>Engine Nameplate</u>	<u>Manufacture Date</u>	<u>NOx Emissions Limit</u>
Nameplate-100≤Bhp<500	Effective January 1, 2008	2 g/bhp-hr
	Effective January 1, 2011	1 g/bhp-hr
Nameplate Bhp≥500	Effective July 1, 2007	2 g/bhp-hr
	Effective July 1, 2010	1 g/bhp-hr

(This Colorado rule may be viewed at <http://www.cdphe.state.co.us/regulations/airregs/5CCR1001-9.pdf>)

Texas - The Texas Commission on Environmental Quality revised its permit by rule (revision date February 17, 2012) for the oil and gas industry sources in Texas, §106.352 Oil and Gas Handling and Production Facilities. The Texas rule provides NOx emissions limitations for the various types of oil and gas sector sources, including NOx emissions limitations for 4-stroke lean burn spark ignition engines. The relevant emissions limitations in the rule include the following:

<u>Engine Type</u>	<u>Manufacture Date</u>	<u>NOx Emissions Limit</u>
Four stroke, lean burn SI-BHP<500	Mfg before 7/1/2008	2g/bhp-hr
	(After 1/1/2030, no 4SLB SI engine NOx emissions shall exceed 2 g/bhp-hr regardless of manufacture date.)	
Four stroke, lean burn SI-BHP≥500	Mfg before 9/23/1982	5g/bhp-hr (exc 8 g/bhp-hr at reduced speed and torque 80%<=100%)
	Mfg before 6/18/92 & BHP<825	5g/bhp-hr (exc 8 g/bhp-hr at reduced speed and torque 80%<=100%)
	9/23/1982≤Mfg<6/18/1992&BHP>825	5g/bhp-hr
	6/18/1992≤Mfg<6/1/2010	2g/bhp-hr (exc 5 g/bhp-hr at reduced speed and torque 80%<=100%)
	Mfg on or after 6/1/2010	1g/bhp-hr

(After 1/1/2030, no 4SLB SI engine NOx emissions shall exceed 2 g/bhp-hr regardless of manufacture date.)

(This Texas rule can be reviewed at:

<http://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/og-easy-2012.pdf>).

Additionally, Texas Administrative Code, Combustion Control at Major Industrial, Commercial, and Institutional Sources in Ozone Non-Attainment Areas, Beaumont-Port Arthur Ozone **Non Attainment** Area Major Sources, Rule §117.105, Emission Specifications for Reasonably Available Control Technology (RACT), provides NOx emissions limitations for natural gas fueled lean burn spark ignition reciprocating engines as follows:

Gas Fueled Lean Burn SI Engine ≥ 300 bhp

3.0 g/bhp-hr

Pennsylvania has recently proposed a revision to its General Permit for Natural Gas Production and Processing Facilities (GP-5). The proposed GP-5 will apply to all spark ignition internal combustion engines and other air contamination sources at natural gas production and processing facilities. In the proposed GP-5, existing rich and lean burn engines with a nameplate rating of less than or equal to 100 horsepower, but less than 1500 horsepower, will be required to continue to meet the existing GP-5 NOx emissions limit of 2 g/bhp-hr. When the currently proposed GP-5 becomes effective, new and reconstructed engines will be required to meet the following NOx emissions limits:

Configuration

New and reconfigured Lean Burn Engine ≤ 100 hp

New and reconfigured Lean Burn Engine $100 < \text{hp} \leq 637$

New and reconfigured Lean Burn Engine > 637 hp

NOx Limit

2 g/bhp-hr

1 g/bhp-hr

0.5 g/bhp-hr

The USEPA established NOx emissions limitations for natural gas fueled lean burn spark ignition engines in 40 CFR Part 60, Subpart JJJJ (NSPS) (1/18/08 73 FR 3567). The applicable NOx emissions limits for lean burn natural gas-fueled, spark ignition engines are as follows:

<u>Engine Type</u>	<u>Output Rating</u>	<u>Manufacture Date</u>	<u>NOx Emissions Limit</u>
SI Nat. Gas Lean Burn	$500 \geq \text{HP} < 1350$	mfg after 7/1/2008	2.0 g/HP-hr
SI Nat. Gas Lean Burn	$500 \geq \text{HP} < 1350$	mfg after 7/1/2010	1.0 g/HP-hr

4.2.3 Discussion of 4-Stroke Lean Burn NOx Reduction Capability – Combustion Controls

With regards to the NOx reduction capabilities of combustion modifications for four stroke lean burn spark ignited reciprocating engines, the literature suggests that there are often significant differences in design characteristics between four stroke lean burn reciprocating engine manufacturers' designs such that applicability and effectiveness of generic NOx combustion controls is highly variable. The literature

suggests that this is sometimes due to the air/fuel mixing characteristics and patterns in the engine cylinders that were employed by the manufacturer in the design of the particular engine model. This would indicate that there is also the likelihood of differences between a given manufacturer's engine models and vintage that could affect the applicability and effectiveness of a given NOx control combustion control technology. For some of the more popular or numerous makes and models, the original manufacturer or an aftermarket vendor may offer effective "off-the-shelf" NOx reduction retrofit packages that help reduce the cost of NOx reduction for those makes and model engines. For other engines, only limited support may be available which could require custom design, installation, and tuning of NOx controls that would tend to increase the cost of the NOx emissions reduction project and possibly impact the overall effectiveness of the project.

Other characteristics may also affect the reduction effectiveness, and the cost effectiveness, of a NOx emissions reduction project on any particular engine, such as frequency of startups and shutdowns, operational loading characteristics, location, (altitude, seasonal variations), etc. Variability also potentially exists from installation to installation due to equipment clearances, etc.

The information suggests that most four stroke lean burn spark ignited reciprocating engines would be responsive to combustion and airflow modifications (potentially including installation/upgrade of turbochargers and inter-cooling, pre-chamber ignition or high energy ignition, improved fuel injection control, air/fuel ratio control, etc). These (or some of these) modifications/upgrades may represent a generic NOx reduction strategy with the potential of reducing NOx emission rates by up to 90% from uncontrolled by facilitating operation with very lean fuel air mixtures. All of the mentioned retrofit NOx controls may not be commercially available for all manufacturers and models of gas compressor four stroke lean burn engines. The actual achievable NOx emission rate, in terms of g/bhp-hr, would tend to be engine design specific. These modifications/upgrades also offer the possibility of improving the four stroke lean burn spark ignited reciprocating engine's efficiency.

There are a number of manufacturers and suppliers that provide components, systems, and services to support combustion related NOx emission reductions from four stroke lean burn engines. Some of these organizations include the following:

- Windrock offers an autobalance system that automatically balances the cylinder-to-cylinder combustion in multi-cylinder slow speed integral engines such as Cooper-Bessemer, Clark/Dresser, Ingersoll-Rand, Worthington, and other two- or four-stroke engines with individual cylinder fuel adjustment valves. The system constantly adjusts fuel flow to each power cylinder in order to maintain peak firing pressures to $\pm 5\%$ of engine average during differing ambient conditions, varying speeds and changing loads. Eliminating unbalanced operation across all operating conditions enables the engine to run with the minimum possible NOx and facilitates the positive results of other NOx reduction modifications. For additional information see: http://www.cookcompression.com/files/comm_id_68/GMJJournal_Q32009_AutoBalance.pdf
- Attainment Technologies company markets gas recirculation systems for NOx control for lean burn spark ignited reciprocating engines. (Gas recirculation as a NOx control for these engines is also being offered by some original equipment manufacturers (OEMs).) With this process, instead of high levels of excess air, re-circulated and cooled exhaust gas is used as a heat sink in the combustion process. High, lean burn reciprocating engine compression ratios can be used without

engine knock complications. Engine performance and fuel efficiency is equivalent to a standard lean burn engine. The advantage compared to traditional lean burn reciprocating engines is the availability of NSCR as an emission after-treatment. This is possible, since there is no excess oxygen in the exhaust stream. Attainment Technologies' literature indicates that retrofitted lean burn engines have achieved NOx emission rates of 0.1 g/bhp-hr in testing using the Attainment Technologies NOx reduction systems. For additional information see:

<http://www.attainmenttech.com/solutions.html>

- Dresser-Rand, a reciprocating engine OEM, offers a retrofit NOx emission technology system for many engine models, including four stroke lean burn spark ignited reciprocating engines. While somewhat dependent upon the specific model, the retrofit NOx emission reduction system may include a screw-in combustion pre-chamber high energy ignition system, earlier fuel injection timing and directional fuel injection for improved air/fuel mixing, improved controls for more precise fuel injection and engine timing, and improved air flow to further lean the mixture when applicable. Dresser-Rand also offers more extensive (and expensive) NOx reduction systems for retrofit, which depending upon engine model may include new cylinder heads with pre-combustion chambers, new main fuel gas injection valves, high efficiency turbochargers, a larger turbocharger combustion air intercooler with plenums, a new fuel management system, an air/fuel ratio controller, a new spark controller, new cams and/or camshaft on four-stroke engines, and a high-energy ignition system. Industry literature indicates that Dresser-Rand offers related NOx controls for KVS, KVSR, KVR, KVT, SVS, TVS, and TVR four stroke engines (Dresser-Rand, Ingersoll-Rand). The literature also indicates that NOx emission guarantees of between 2.5 g/bhp-hr and 3.0 g/bhp-hr have been provided with these NOx reduction technologies, and that those guarantees have been consistently met or improved upon. For additional information see:
<http://dresser-rand.com/service/engineeredolutions/revamps/ recip.php>, <http://www.dresser-rand.com/techpapers/tp014.pdf>
- Dresser Rand also indicates that they have considerable experience in the retrofit of NOx emissions controls across a broad range of existing legacy natural gas compression lean burn reciprocating engines. Their products and systems include a high-pressure fuel injection system, a real-time engine and compressor monitoring platform, high delivery ratio turbochargers designed for the performance requirements of emission reduction packages, a low emissions reduction (LEC) kit and a variety of products designed to reduce emissions while expanding the operating envelope, model-based control strategies that provide operational flexibility, adaptive air/fuel ratio controllers, and catalytic exhaust emissions control systems. Dresser Rand indicates that they have experience in working with a number of engine makes and models, including Caterpillar (3500 Series and 3600 Series), Cooper Bessemer (GMW, GMWA, GMV, GMVH, V-250, W-330, LSV, Quad 12), Clark (BA, HBA, TLA, TCV, TCVA, TCVC, TCVD), Ingersoll Rand (KVG, KVS Series, KVTR, KVGR, LVG, PVG, PSVG, SVG), Nordberg (FSE), White Superior (825, 2416), Wartsilla (18V34SG), Waukesha (3521, 5790, 7042), and Worthington (UTC, UTC-T, Mainliner (ML), Mainliner (MLV)). For additional information see: <http://www.dresser-rand.com/service/engineeredolutions/engineuity/solutions/emissions.php>
- Compression Components Texas (CCT) advertises a retrofit kit for Caterpillar G3516 natural gas fueled four stroke lean burn spark ignited reciprocating engines that enable the engine to meet a 0.15 g/hp-hr NOx emission rate limit with little or no loss in engine power. The CCT kit is comprised of a group of combustion related improvements/upgrades and does not incorporate any post-

combustion controls. For additional information see:
http://www.compressioncomponentstx.com/-/Low_NOx.html

- Caterpillar offers new lean burn spark ignited reciprocating engines with a wide range of output ratings up to approximately 5000 HP with a broad operating speed range. Caterpillar advertises that many of these engines are capable of achieving NOx emissions limits of 0.5 g/bhp-hr without post-combustion NOx emission controls. For additional information see:
<http://catoilandgas.cat.com/products/engines>
- Dresser Waukesha offers new 12 cylinder and 16 cylinder versions of its 275GL lean burn engine for the gas compression market. The engines are reported to be able to achieve NOx emission rates of less than 0.5 g/bhp-hr, and are rated at 3,625 hp for the 12 cylinder version and 4,835 hp for the 16 cylinder version. For additional information see: <http://www.pipelineandgasjournal.com/12-16-cylinder-versions-low-emission-compressor-engine-unveiled>

In 2007 the Illinois Environmental Protection Agency prepared its “Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines”. This document reviewed NOx emissions control capabilities and estimated cost effectiveness for a number of NOx controls for lean burn reciprocating engines. Included in this evaluation for lean burn spark ignited reciprocating engines is the installation of a low emissions control (LEC), layered NOx control system. The document indicates that LEC has the capability of reducing NOx emissions from lean burn engines by approximately 80% to 93%. The following summarizes the lean burn spark ignited reciprocating engine evaluation:

<u>Type of Control</u>	<u>Nameplate Rating (HP)</u>	<u>Total Capital Cost (2004 \$)</u>
Low Speed LB Layered Comb	500 – 11,000	751,600 – 4,249,700
Med Speed LB Layered Comb	500 – 11,000	130,300 – 2,149,300

For additional information see: <http://www.epa.state.il.us/air/rules/rice/tsd-rice.pdf>

The industry information suggests that most four stroke lean burn spark ignited reciprocating engines would be responsive to combustion and airflow modifications (potentially including installation/upgrade of turbochargers and inter-cooling, pre-chamber ignition or high energy ignition, improved fuel injection control, air/fuel ratio control, etc). All of the combustion related NOx controls may not be commercially available for all manufacturers and models of four stroke lean burn spark ignited reciprocating engines. It appears that the actual achievable NOx emission rate, in terms of g/bhp-hr, would tend to be engine design specific. Additionally, site specific installation issues may be greatly problematic or not cost effective. These engine and site specific issues are not altogether different than issues encountered with other types of emissions reduction technologies and projects. These types of issues can usually be addressed by providing appropriate flexibility in any rulemaking that includes consideration of site specific issues.

The available information suggests that retrofit combustion related modifications have the potential to achieve an approximate 90% reduction in NOx emissions from most four stroke lean burn spark ignited engines, given potential variability between engine designs. This suggests an approximate range of NOx emissions rate of 0.5 g/bhp-hr to 2.0 g/bhp-hr from otherwise uncontrolled lean burn spark ignited reciprocating engines, depending upon the make/model configuration of the engine.

The industry information also indicates that there is a wide range of estimated costs for installation of combustion related controls with a target NOx emissions rate of 0.5 g/bhp-hr. One source of information estimated a range of cost is from \$245 per rated horsepower to \$1475 per rated horsepower. The range in cost appears to be affected more by the make/model/configuration of the engine rather than strictly by the size of the engine. Some reasons for this include that some engines will require the installation of new turbocharger and auxiliaries, some engines will require relatively easy upgrades to existing turbochargers and auxiliaries, some engines will require head modifications to accept pre-combustion chamber ignitions while others can utilize screw in pre-combustion chamber ignition systems, etc.

4.2.4 Discussion of 4-Stroke Lean Burn NOx Reduction Capability – Post Combustion Controls

With regards to the NOx reduction capabilities of post combustion modifications for four stroke lean burn spark ignited reciprocating engines, the literature suggests that SCR is technically feasible to achieve significant NOx emission rate reductions from four stroke lean burn engines. However, some industry trade organizations indicate that there are problems that make the installation and successful operation of SCR questionable.

In a presentation titled “Challenges in Retrofitting Selective Catalytic Reduction (SCR) Systems to Existing Stationary Natural Gas Fired Engines” that was presented at the October 5, 2011 Gas Machinery Conference, it was stated that applying SCR to pipeline engines is not feasible because the exhaust temperatures are below the operating window for SCR or at a level where the SCR effectiveness is reduced, that the exhaust temperature is below the temperature range for reliable decomposition of urea into ammonia, and the effectiveness of SCR has not been demonstrated on the slow speed, large bore, low exhaust temperatures typical of gas pipeline reciprocating engines. For additional information see:

<http://www.gmrc.org/ckfinder/userfiles/files/GMC%20Conf/Final%20Papers/Challenges%20in%20Retrofitting%20SCR%20Systems.pdf>

However, there are a number of organizations that market SCR systems that indicate that their catalysts are capable of effectively operating over a wide range of exhaust gas temperature. Such catalysts would serve to offer considerable flexibility for application to varying makes/models of four stroke lean burn engines, as well as providing flexibility for effective NOx reduction over a range of operating conditions for those engines.

Another stated issue with the use of SCR for four stroke lean burn spark ignition reciprocating engines is that many compressor facilities are unmanned and that SCR installations have not been demonstrated in unmanned facilities. Other industry information indicates that while it may be true that there are currently few SCRs in unmanned facilities, with modern software based controls and supervisory control and data acquisition (SCADA) type communication technologies there does not appear to be any technical barrier to operating the SCR related controls and auxiliaries successfully from a remote location.

It has also been stated by the gas industry that SCRs have not been demonstrated on combustion devices with variable loads. SCR manufacturers offer catalysts that are effective over wide temperature

ranges characteristic of a range in engine operating load. Modern controls also have the ability to closely regulate fuel and air flows to ensure combustion gas oxygen and temperature levels at expected levels and to regulate reagent flow, all serving to ensure proper SCR function over a broad range of load.

The industry trade organizations have also pointed out that many compressor locations are remote and do not include immediate access to an electric supply capable of handling the pumps, etc that are necessary for an SCR system. While this may be a true statement, not all compressor facilities are without access to electric supply resources. Further, any rules or regulations that support NO_x emissions limits based on SCR NO_x removal capabilities could be configured to offer alternatives for sites with acceptable justification for being unable to attain those limits.

The Manufacturers of Emission Controls Association (MECA) has stated that the commercial use of SCR systems for the control of NO_x emissions from lean-burn stationary engines has been in place since the mid-1980s in Europe and since the early 1990s in the US. According to MECA, since 1995, one MECA member company has installed over 400 SCR systems worldwide for stationary engines with varying fuel combinations, including dozens of natural gas powered compressor engines at sites in the US. MECA indicated that these four stroke lean burn gas compressor engines equipped with urea-SCR achieved in excess of 90% reduction in NO_x emissions. Comments from MECA indicate that their member experience is that NO_x emission rates of 0.2 g/hp-hr to 0.5 g/hp-hr are representative of modern SCR technology on these engines.

Even though some industry sources indicate that SCR is not a practical or proven NO_x reduction technology for four stroke lean burn spark ignition reciprocating engines, the information suggests that SCR is not technically infeasible from a generic standpoint. There are a number of manufacturers and suppliers that offer SCR systems that may be used on four stroke lean burn spark ignited reciprocating engines. Some of the manufacturer and supplier information is provided below:

- EF&EE (Engines, Fuel & Emissions Engineering Incorporated) announced on November 10, 2010, that it had received an order from Clean Air Power, Inc. for six SCR reductant metering and control systems. These systems were due to be delivered by the end of 2010, to be installed on large, lean-burn natural gas compressor engines at gas storage sites in Texas and Mississippi. For additional information see: <http://www.efee.com/news.html>
- EF&EE, on November 22, 2010, also announced Compact SCR(tm) system that enables conventional lean-burn natural gas and biogas engines to meet the California ARB Distributed Generation standard of 0.07 pounds of NO_x per megawatt-hour. For additional information see: <http://www.efee.com/news.html>
- Caterpillar literature indicates that they offer SCR systems for many of their lean burn spark ignition reciprocating engine models, for both new engine installations and existing engine retrofits. Caterpillar indicates that NO_x reductions of up to 95% are possible utilizing SCR.
- Johnson Matthey markets urea based SCR systems that reduce NO_x emissions from lean burn natural gas fueled engines by 90% or more. Johnson Matthey offers catalysts with a broad effective operating temperature range to achieve NO_x reductions earlier in an engine operating cycle and across a wide engine operating range. For additional information see: <http://ect.jmcatalysts.com/site.asp?siteid=836&pageid=888&furtherid=946>

- CleanAir Systems offers a SCR system that they advertise as being applicable to lean burn natural gas fired engines, including those utilized for gas compression. CleanAir indicates that their SCR catalyst allows NOx reduction operation in a wide range of temperatures, from approximately 300 degF to approximately 1000 degF. (CleanAir Systems was acquired by Caterpillar in 2010, and is now called CleanAir Systems, A Caterpillar Company.) Their lean burn engine SCR product is now being referred to as E-Pod SCR. CleanAir indicates that their lean burn engine capable SCR achieves up to 95% reduction in NOx emissions across a wide range of exhaust temperatures. For additional information see: <http://www.cleanairsys.com/products/hybrids/index.htm>
- Clean Air Power has a case study, dated 3/4/2009, indicating that they had supplied four SCR units (in 2006, with an additional 2 ordered for 2009 delivery) for emissions control of natural gas fueled spark ignition reciprocating engines at the Pine Prairie Energy Center, a salt cavern natural gas storage facility in Louisiana. FERC information indicates that the Pine Prairie Energy Center was incorporating six Caterpillar G16CM34 reciprocating engines, each rated 8,100 HP. For additional information see: <http://www.cleanairpower.com/emissionCasestudies.php?mode=details&libraryId=2&start=0&caseId=TXpVPQ>
- Clean Air Power has a case study, dated 3/4/2009, indicating that they had supplied an SCR unit for a Caterpillar G3616 natural gas engine located at the salt cavern natural gas storage/hub services facility EXTERRAN/TRESPALACIOS in Texas. For additional information see: <http://www.cleanairpower.com/emissionCasestudies.php?mode=details&libraryId=2&start=0&caseId=TXpZPQ==>
- Clean Air Power has a case study, dated 3/4/2009, indicating that they were involved in a project that would include supplying four SCR units for natural gas fueled Caterpillar G3616 engines at the EXTERRAN / LEAF RIVER facility in Mississippi. This facility is a salt cavern natural gas storage and delivery site. For additional information see: <http://www.cleanairpower.com/emissionCasestudies.php?mode=details&libraryId=2&start=0&caseId=TXpnPQ==>
- Miratech Corporation offers a SCR based NOx reduction system that is advertised to be applicable to lean burn engines used in natural gas compression applications. Miratech indicates that NOx reductions of up to 99% are achievable with their SCR system. For additional information see: http://www.miratechcorp.com/images/data/attachments/0000/0019/SCR_Systems.pdf

In 2007 the Illinois Environmental Protection Agency prepared its "Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines". This document reviewed NOx emissions control capabilities and estimated cost effectiveness for a number of NOx controls for lean burn reciprocating engines. Included in this evaluation for lean burn engines is the application of SCR for NOx control. The document indicates that SCR has the capability of reducing NOx emissions from lean burn engines by approximately 90%. The following summarizes the lean burn engine SCR evaluation:

<u>Type of Control</u>	<u>Nameplate Rating (HP)</u>	<u>Total Capital Cost (2004 \$)</u>
Lean Burn SCR	550 – 11,000	457,500 – 1,451,000
For additional information see: http://www.epa.state.il.us/air/rules/rice/tsd-rice.pdf		

In support of its development of Rule 4702, Internal Combustion Engines Phase 2, in 2003 the San Joaquin Valley Air Pollution Control District prepared a cost effectiveness analysis for the retrofit installation of SCR on natural gas fueled lean burn spark ignited internal combustion engines. The analysis was performed for a range of engine output ratings. The analysis assumed the installation would achieve compliance with a proposed NOx emissions rate limit of 65 ppmvd @15% O2 (approximately 0.89 g/bhp-hr). The results of the analysis for lean burn spark ignition engines is summarized below:

<u>Lean Burn Engine SCR NOx Reduction Control Installation Cost Estimation</u>					
Nameplate Rating (hp)	SCR	Annual	Annualized	25% Cap Fact	75% Cap Fact
	Installed Cost (\$)	O&M Cost (\$)		Cost Effectiveness (\$/ton)	Cost Effectiveness (\$/ton)
50	45000	20102	27424	24593	8198
200	45000	26102	33424	7493	2498
500	60000	35102	44864	4023	1341
1000	149000	78102	102344	4589	1530
1500	185000	117102	147202	4400	1467

Note: Annualized cost based on 10 year life and 10% interest.

NOx reductions based on 9.55 g/bhp-hr pre-installation and 0.37 g/bhp-hr post-installation.

For a additional information see:

http://www.arb.ca.gov/pm/pmmeasures/ceffect/reports/sjvapcd_4702_report.pdf

4.2.5 Four Stroke Lean Burn Spark Ignition Reciprocating Engine NOx Control Summary

Industry information indicates that there are technically feasible, commercially available NOx reduction technologies applicable to natural gas fueled, spark ignited, lean burn reciprocating engines. The information suggests that most of these engines would be responsive to combustion and airflow modifications (potentially including installation/upgrade of turbochargers and inter-cooling, pre-chamber ignition or high energy ignition, improved fuel injection control, air/fuel ratio control, etc). The industry information also indicates that there are technically feasible, commercially available post-combustion (SCR) NOx reduction systems available for use on these same engines, with MECA indicating that NOx emission rates in the range of 0.2 g/hp-hr to 0.5 g/hp-hr being achievable utilizing SCR on these engines. However, some of the combustion related and post combustion NOx controls may not be commercially available for all manufacturers and models of four stroke lean burn spark ignited reciprocating engines.

From the industry information it appears that the actual achievable NOx emission rate, in terms of g/bhp-hr, would tend to be engine design specific. Additionally, site specific installation issues may impact controls installation such that the installations are operationally problematic or not cost effective. These engine design and site specific issues are not altogether different than issues encountered with other types of emissions reduction technologies and projects, and can usually be

addressed by providing appropriate flexibility in any rulemaking that includes consideration of site specific issues.

The information therefore seems to support NOx emission rate limits of as low as 0.5 g/bhp-hr for many four-stroke lean burn spark ignition reciprocating engines with a nameplate rating of 250 hp or above, providing that there is consideration of individual engine design and site specific flexibility provisions. For four stroke lean burn spark ignited reciprocating engines with nameplate ratings below 250 hp, the available industry information indicates NOx emission rate limits of around 3 g/bhp-hr for some of the existing popular make/model combinations. Again, this could be addressed with appropriate rule or regulation consideration of individual engine design and site specific flexibility provisions.

Very little information was found regarding the cost of purchase and installation of combustion related and post-combustion NOx controls for four stroke lean burn engines. The following summarizes the limited information:

Type of NOx Control	Engine Size Range (hp)	Estimated Range of NOx Reduction	Estimated Range of NOx Emissions Rate	NOx Control Estimated Costs (\$)
		(%)	(g/bhp-hr)	
Layered Combustion	100 - 250	60 - 90	0.5 - 3	182,000 - 456,000
Layered Combustion	500 - 11000	90	0.5	143,000 – 4,666,000
SCR	2000 - 2500	90	0.2 - 0.5	502,000 – 1,593,000

Note: Estimated control costs are initial capital cost estimates only. Costs are based on Illinois' "Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines", adjusted for CPI.

It should be noted that the range of costs, especially for the combustion related NOx control modifications, is more representative of the diversity of the modifications that might be required to attain the NOx emission rate limits rather than a function of the nameplate rating of the engine. This is due to the fact that some engines may require complete new turbocharger systems with related auxiliaries, while some may require relatively modest modifications to existing systems, some may require new PCC combustion ignition systems while others may require only minor improvements, etc. These differences can exist across the range of four stroke lean burn spark ignited reciprocating engine nameplate ratings. As discussed earlier, applicability and effectiveness of a given NOx control technology to a particular engine may vary by engine make, model, vintage, location, and operating characteristics.

4.3 Reciprocating Engines - Four Stroke Rich Burn Spark Ignition Engines

In a reciprocating engine, combustion of a compressed fuel-air mixture is used to drive pistons in one or more cylinders, with the linear piston motion converted to rotary motion with a crankshaft. The rotary motion developed by the reciprocating engine may then be utilized to drive natural gas compressors, pumps, mechanical drives, or other rotary loads. Spark ignition engines use a spark (across a spark plug) to ignite the compressed fuel-air mixture to create the motive force.

Four-stroke spark ignition reciprocating engines use a separate engine revolution for the intake/compression stroke and the power/exhaust stroke. Four-stroke reciprocating engines complete the combustion cycle in two revolutions of the crankshaft. Each of the piston's four strokes has an important function in the engine cycle (intake, compression, power and exhaust). These engines have intake and exhaust valves to introduce combustion air into the cylinder and exhaust combustion gases from the cylinder. Most four-stroke spark ignition reciprocating engines use open-chamber spark plugs to ignite the air/fuel mixture. These engines may be either naturally aspirated, using the suction from the piston to entrain the air charge, or utilize a supercharger or turbocharger to pressurize the inlet air/fuel charge.

Rich-burn four-stroke spark ignited reciprocating engines are configured to operate at or near a stoichiometric air/fuel ratio with little or no excess air. The engines can be carbureted or fuel injected, and they use the intake stroke of the piston to draw air into the cylinder (naturally aspirated). Manufacturers have added superchargers and turbochargers to increase the delivery of combustion air, which increases horsepower output capability. Because the air-to-fuel ratio is rich with fuel, more fuel is used, which results in increased combustion temperatures, increased engine power, and decreased engine efficiency relative to a lean burn engine.

There are a number of four stroke rich burn (4SRB) spark ignition reciprocating engines in service in the oil and gas sector, representing several manufacturers and model numbers.

4.3.1 Four Stroke Rich Burn Spark Ignition Engine NOx Controls

Industry literature indicates that application of high energy ignition systems on rich burn spark ignited reciprocating engines has the potential of resulting in modest NOx emissions by providing a more stable combustion over an engine's entire operating range. The high energy ignition system is generally a conventional open-chamber system with the spark plug (or plugs) generally located with the spark plug protruding from the bottom of the combustion cylinder head into the combustion chamber. High energy ignition systems allow more energy to be delivered to the spark plug(s) with a larger gap, thereby increasing the spark energy delivered to the air/fuel mixture and ensuring proper ignition. High energy ignition systems may be digitally controlled systems that use crankshaft referenced angle encoders to deliver precise, high energy ignition sparks. These high energy ignition systems may have the capability to generate multiple, successive sparks during combustion to ensure proper air/fuel light-off. Modern high energy ignition systems tend to reduce misfires and engine detonation, and provide a more stable combustion over an engine's entire operating range. Industry information indicates that a slight NOx emissions reduction, approximately 10%, can be achieved through application of a high energy ignition system on an engine that does not have an existing high energy ignition system.

Non Selective Catalytic Reduction (NSCR) is an effective NO_x reduction technology for rich burn spark ignited reciprocating engines that exhibit low levels of excess oxygen in the exhaust. A NSCR, or three way catalyst, is similar to the catalyst controls installed on most modern automobiles. Exhaust from the engine is passed through a metallic or ceramic honeycomb covered with a platinum group metal catalyst. The catalyst promotes the low temperature (approximately 850 degF) reduction of NO_x into N₂, the oxidation of CO into CO₂, and the oxidation of VOCs into H₂O and CO₂. NSCR catalyst efficiency is directly related to the air /fuel mixture and temperature of the exhaust. Efficient operation of the catalyst requires the engine exhaust gasses contain no more than 0.5% O₂. In order to obtain the proper exhaust gas O₂ across the operating range, an air/fuel ratio controller is installed that measures the oxygen concentration in the exhaust and adjusts the inlet air fuel ratio to meet the proper 0.5% O₂ exhaust requirement for varying engine load and engine speed conditions and varying ambient conditions. Industry literature indicates that the proper use of NSCR on four-stroke rich burn spark ignition reciprocating engines has NO_x reduction capabilities of up to 99%, with NO_x emission rates below 0.5 g/bhp-hr. Industry information indicates that, across the US, there are thousands of existing NSCR installations. [Retrofit installation of NSCR on five Caterpillar rich burn engines in Texas achieved a NO_x reduction of 96% or greater on all of the engines. On two of those engines, testing conducted after more than 4000 hours of operation with the NSCR indicated the NSCR controls were still achieving 95% NO_x reduction.]

As indicated above, proper control of the air/fuel ratio is important for optimizing the emissions performance of NSCR equipped engines, as industry information indicates that post-catalyst emissions are dependent upon pre-catalyst oxygen concentration. Industry information indicates that there is a trade off between NO_x emissions and CO, ammonia, and hydrocarbon emissions, generally requiring air/fuel ratio control within a tight band to attain simultaneous low levels of NO_x and CO emissions. If the engine's air/fuel ratio drifts to a fuel rich operation, NO_x emissions tend to decrease while CO, ammonia, and hydrocarbon emissions tend to increase. If the engine's air/fuel ratio drifts to a fuel lean operation, NO_x emissions tend to increase while CO, ammonia, and hydrocarbon emissions tend to decrease. For this reason, accurate control of the engine air/fuel ratio is considered to be an integral requirement for the successful application of NSCR for NO_x emissions reduction.

Some industry literature suggests that some particular 4-stroke rich burn spark ignition reciprocating engines can be converted to lean burn configurations with the accompanying lean burn engine NO_x reduction capabilities. One vendor indicates that conversion to a lean burn configuration and the use of exhaust gas recirculation delivers the advantages of a lean burn engine's efficiency and the rich burn engine's capability of utilizing NSCR for NO_x control. The ability to convert a rich burn engine to a lean burn configuration is highly unit specific and does appear to have had widespread application in industry.

4-Stroke Rich Burn Spark Ignition Engine

NOx Control Retrofit Technology

Potential NOx Reduction

High Energy Ignition System	10%
NSCR Catalyst (with air/fuel ratio controller)	90% - 99%

4.3.2 Example Existing Rules and Regulations – 4SRB

California - California's South Coast Air Quality Management District (SCAQMD) has established Rule 1110.2, Emissions from Gaseous and Liquid Fueled Engines, the latest revision of the rule dated July 2010. Rule 1110.2 regulates NOx emissions from new and existing stationary spark or compression ignition internal combustion engines with a nameplate rating of 50 hp or greater. (This rule, 1110.2, may be accessed from <http://aqmd.gov/rules/download.html>)

NOx emission limits noted in SCAQMD Rule 1110.2 applicable to existing stationary spark and compression ignition engines include:

Nameplate - Bhp $\geq$ 500	36 ppmvd NOx (<i>approximately 0.5 g/bhp-hr</i>)
Nameplate - Bhp<500	45 ppmvd NOx (<i>approximately 0.6 g/bhp-hr</i>)
Effective July 1, 2010	
Nameplate - Bhp $\geq$ 500	11 ppmvd NOx (<i>approximately 0.15 g/bhp-hr</i>)
Nameplate - Bhp<500	45 ppmvd NOx (<i>approximately 0.6 g/bhp-hr</i>)
Effective July 1, 2011	
Nameplate - All	11 ppmvd NOx (<i>approximately 0.15 g/bhp-hr</i>)

(Note that SCAQMD Rule 1110.2 contains exemptions for units that operate less than 500 hrs/yr or burn less than 100 MMBTU/yr.) (Note that the rule makes no distinction for rich burn, lean burn, etc stationary engines.)

California – California's San Joaquin Valley Air Pollution Control District's Rule 4702, Internal Combustion Engines, amended August 18, 2011, regulates NOx emissions from stationary spark and compression ignition engines with nameplate ratings of 25 hp and greater. (This rule may be viewed at <http://www.arb.ca.gov/DRDB/SJU/CURHTML/R4702.PDF>)

The NOx emissions limits noted in the San Joaquin Valley Air Pollution Control District's Rule 4702 for rich burn engines with nameplate ratings of greater than 50 hp and not used for agricultural operations include:

Rich burn, waste gas fueled	50 ppmvd NOx
Rich burn, cyclic loaded, field gas fueled	50 ppmvd NOx
Rich burn, limited Use	25 ppmvd NOx
Rich burn, all others	11 ppmvd NOx

(Note that the San Joaquin Valley Air Pollution Control District's Rule 4702 definition of limited use requires the engine have a permit restricting the engine's operation to no more than 4000 hrs/yr.)

Colorado - The state of Colorado's Air Quality Control Commission has established NOx emissions limitation for stationary spark ignited internal combustion reciprocating engines in its Regulation 7, Control of Ozone Via Ozone Precursors (Emissions of Volatile Organic Compounds and Nitrogen Oxides). (This rule may be viewed at <http://www.cdphe.state.co.us/regulations/airregs/5CCR1001-9.pdf>) NOx emissions limits noted in Colorado's Regulation 7 applicable to existing stationary natural gas fueled rich burn reciprocating internal combustion engines include:

Rich Burn Engine Nameplate – BHP>500 Install NSCR and AFR by July 1, 2010
(Note: The rule includes a \$5000/ton cost effectiveness exemption for combined NOx and VOC reductions from rich burn engines.)

NOx emissions limits noted in Colorado's Regulation 7 applicable to new, modified, or relocated stationary natural gas fueled reciprocating internal combustion engines include:

Nameplate-100≤Bhp<500	
Effective January 1, 2008	2 g/bhp-hr
Effective January 1, 2011	1 g/bhp-hr
Nameplate Bhp≥500	
Effective July 1, 2007	2 g/bhp-hr
Effective July 1, 2010	1 g/bhp-hr

Texas - The Texas Commission on Environmental Quality revised its permit by rule (revision date February 17, 2012) for the oil and gas industry sources in Texas, §106.352 Oil and Gas Handling and Production Facilities. The Texas rule provides NOx emissions limitations for the various types of oil and gas sector sources, including NOx emissions limitations for 4-stroke lean burn spark ignition engines. The relevant emissions limitations in the rule include the following:

Rich Burn SI Engines – BHP ≥ 500	Mfg before 1/1/2011	2g/bhp-hr
	Mfg on or after 1/1/2011	1g/bhp-hr
	After 1/1/2020, regardless of mfg date	1g/bhp-hr

(This rule can be reviewed at:
<http://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/og-easy-2012.pdf>).

Additionally, Texas Administrative Code, Combustion Control at Major Industrial, Commercial, and Institutional Sources in Ozone Non-Attainment Areas, Beaumont-Port Arthur Ozone NonAttainment Area Major Sources, Rule §117.105, Emission Specifications for Reasonably Available Control Technology (RACT), provides NOx emissions limitations for rich burn spark ignited engines as follows:

Gas Fueled Rich Burn SI Engine ≥ 300 bhp	2.0 g/bhp-hr
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Pennsylvania has recently proposed a revision to its General Permit for Natural Gas Production and Processing Facilities (GP-5). The proposed GP-5 will apply to all spark ignition internal combustion engines and other air contamination sources at natural gas production and processing facilities. In the

proposed GP-5, existing rich and lean burn engines with a nameplate rating of less than or equal to 100 horsepower, but less than 1500 horsepower, will be required to continue to meet the existing GP-5 NOx emissions limit of 2 g/bhp-hr. When the currently proposed GP-5 becomes effective, new and reconstructed rich burn engines will be required to meet the following NOx emissions limits:

Configuration

New and reconfigured Rich Burn Engine - All

NOx Limit

0.2 g/bhp-hr

The USEPA established NOx emissions limitations for natural gas fueled rich burn spark ignition engines in 40 CFR Part 60, Subpart JJJJ (NSPS) (1/18/08 73 FR 3567). The applicable NOx emissions limits for rich burn natural gas-fueled, spark ignition engines are as follows:

Engine Type	Output Rating	Manufacture Date	NOx Emissions Limit
SI Nat. Gas	100≤HP<500	mfg after 7/1/2008	2.0 g/HP-hr
SI Nat. Gas	100≤HP<500	mfg after 1/1/2011	1.0 g/HP-hr
SI Nat. Gas	HP≥500	mfg after 7/1/2007	2.0 g/HP-hr
SI Nat. Gas	HP>500	mfg after 7/1/2010	1.0 g/HP-hr

4.3.3 Discussion of Four Stroke Spark Ignition Engine NOx Reduction Capability – Combustion Modifications

Industry literature indicates that there are relatively few highly effective combustion related NOx emission controls utilized for four stroke rich burn spark ignition engines, other than ignition related controls that would be expected to have only minor NOx reduction benefits. Industry literature suggests that some individual model four stroke rich burn spark ignition engines can be converted to a lean burn configuration with the potential of achieving NOx reductions similar to those of other lean burn engines. However, the literature suggests that such conversion capabilities appear to be very limited and expensive.

Some information that was found regarding combustion controls for NOx reduction from rich burn engines is summarized below:

- A 1999 paper by Enginuity (now part of Dresser-Rand) discusses a project to install NOx reduction combustion controls on five 1950's vintage Ingersoll Rand KVG-103 four stroke rich burn carbureted engines rated at 1000hp each. The project included the installation of a turbocharger and related auxiliaries, removal of the carburetor and installation of single point fuel injection and related controls, installation of a screw-in pre-combustion chamber to improve ignition, and improved engine controls. NOx emissions were reduced 80% to 90% to below 2 g/bhp-hr across the engines' load range, with improvements in fuel consumption. For additional information see: <http://www.dresser-rand.com/techpapers/tp149.pdf>

- Attainment Technologies company markets gas recirculation systems for NOx control for four stroke rich burn spark ignition engines. (Exhaust gas recirculation as a NOx control for these engines is also being offered by some original equipment manufacturers (OEMs).) Attainment Technologies' literature indicates that the use of their rich burn engine NOx reduction process can lower the engine out NOx emissions by up to 80%. The NOx reduction is accompanied by a higher power output and better fuel efficiency when a higher compression ratio can be used. Experience with a Caterpillar 3516 turbocharged engine showed an increase in power output by 10% and a decrease in fuel consumption of 7% when this principal is applied. Attainment Technologies' literature indicates that retrofitted rich burn spark ignition reciprocating engines have achieved NOx emission rates of 0.1 g/bhp-hr in testing using the Attainment Technologies NOx reduction systems. For additional information see: <http://www.attainmenttech.com/solutions.html>
- Caterpillar literature indicates that they offer emissions upgrade groups for retrofit for certain of its engine models, including many 3306 and 3406 models. These emissions upgrade groups may include an upgraded turbocharger, fuel pump/governor, nozzles, cylinder pack, after-coolers (if applicable), and installation parts.

4.3.4 Discussion of NOx Reduction Capability – Post Combustion Modifications

Industry literature suggests that the use of non-selective catalytic reduction NOx controls (both in new and retrofit application), in conjunction with a modern air/fuel controller, on four stroke rich burn engines is a highly effective NOx control for these engines and has been installed in relatively high numbers. NSCR controls are available from a number of suppliers including some engine OEMs. With modern air/fuel controllers, the NSCR is an effective NOx control over a broad range of engine operation. The data suggests that there are many NSCRs in successful service on four stroke rich burn spark ignition reciprocating engines, and the controls have been installed on four stroke rich burn reciprocating engines representative of a wide range of engine nameplate ratings. Industry literature suggests that NOx control in excess of 90% can be expected through utilization of NSCR and air/fuel ratio controller on an otherwise uncontrolled four stroke rich burn engine. Information from MECA indicated that the experience of their members indicates that modern NSCR and air fuel ratio controller installations on these engines can support 99% reductions in NOx emissions and can achieve NOx emission rates in the range of 0.2 g/hp-hr to 0.5 g/hp-hr.

While NSCR is considered a post-combustion control, successful application of the NSCR usually also requires the installation of a modern air fuel ratio controller (AFRC). The AFRC is necessary to properly manipulate the engine combustion parameters across the rich burn engine's operating range in order to maintain the exhaust gas excess oxygen in the range required for proper, efficient operation of the NSCR. Because successful, efficient operation of the NSCR is dependent upon proper control of an AFRC, the further discussion of NSCR below implies the simultaneous installation of an appropriate AFRC. There are a number of manufacturers of air fuel ratio controllers, including the following:

- Altronic Inc. offers a variety of air fuel ratio controllers to support operation of a wide range of engines, for both new installation and retrofit applications. For additional information see: <http://altronicinc.com/index.html>
- Continental Controls offers air fuel ratio control for a range of gas fueled engines for both new and retrofit applications. For additional information: <http://www.continentalcontrols.com/index.php>

- Woodward Governor Company offers air fuel ratio control for a range of gas fueled engines for both new and retrofit applications. For additional information see: <http://www.woodward.com/airfuelratiocontrol.aspx>

There are a number of manufacturer's and suppliers that offer NSCR systems that may be used on four stroke rich burn spark ignition reciprocating engines. Some of the manufacturer and supplier information reviewed is summarized below:

- A presentation by Environ, *Demonstration of NOx Emission Controls for Gas Compressor Engines, A Study for Northeast Texas Presented by ENVIRON*, dated December 6, 2005, discussed a study where NSCR NOx controls were installed on existing Caterpillar rich burn engines with output rating from 145 hp to 265 hp. After installation of the NSCR controls, NOx emissions were reduced to a range of 0.3 g/bhp-hr to 0.5 g/bhp-hr. The document indicated that the average cost was \$10,622 per engine, including the NSCR module, an AFR controller, a solar power unit, and installation labor. For additional information see: http://www.epa.gov/glo/SIPToolkit/documents/12-20-05_rich-burn_engine_control_briefing.pdf (The above project was more completely documented in "A Pilot Project to Assess the Effectiveness of an Emission Control System for Gas Compressor Engines in Northeast Texas", Final Report, November 4, 2005, <http://www.scribd.com/doc/1597001/Environmental-Protection-Agency-NETAC-Compressor-Retrofit-Final-Report-110405>)
- DCL International Inc. offers NSCR catalyst systems for a wide range of sizes of rich burn stationary engines. For additional information see: <http://www.dcl-inc.com/home>
- Dresser-Rand markets NSCR systems for NOx reduction from rich burn engines, as both new unit installations and for retrofit to existing engines. For additional information see: http://dresser-rand.com/literature/engenuity/2187_Engenuity-Compi_catsys.pdf
- Caterpillar literature indicates that they offer NSCR systems for many of their rich burn engine models, for both new engine installations and existing engine retrofits. Caterpillar indicates that NOx reductions of up to 95% are possible utilizing NSCR.
- CleanAir Systems offers a NSCR NOx reduction catalyst for rich burn engines, including those utilized for gas compression. (CleanAir Systems was acquired by Caterpillar in 2010, and is now called CleanAir Systems, A Caterpillar Company.) CleanAir Systems' NSCR is now referred to as ASSURE TWC (three way converter). The use of an air fuel ratio controller is also recommended in these applications, and they are also offered by CleanAir Systems. CleanAir Systems indicates that their ASSURE TWC NSCR can achieve NOx emission reductions up to 99%. For additional information see: <http://www.cleanairsys.com/products/converters/ASSURE-OC-TWC.htm>
- Miratech Corporation offers a NSCR catalyst system for NOx reduction from rich burn engines used in natural gas compression applications. For additional information see: <http://www.miratechcorp.com/site/miratech/section/17>
- Johnson Matthey markets 3-way catalyst systems that reduce NOx emissions from rich burn natural gas fueled engines by 95% or more, and able to achieve NOx emission rates down to approximately

0.07 g/bhp-hr. For additional information see :
<http://ect.jmcatalysts.com/site.asp?siteid=836&pageid=888&furtherid=946>)

- A 2009 brochure from Dresser Waukesha indicates that new Waukesha rich burn engines are commercially available with horsepower ratings up to 1,980 hp and, equipped with NSCR, achieve NOx emissions levels below 0.15 g/bhp-hr. For additional information see:
http://www.dresserwaukesha.com/documents/1256_0309.pdf

In an April 28, 2006 memo from Alpha-Gama Technologies to the USEPA, Control Costs for Reciprocating Internal Combustion Engines at Major and Area Sources, cost estimates were prepared for the installation of NSCR on four stroke rich burn engines. For capital cost estimates, the following equation was determined: NSCR Capital Cost = 19.7 * HP + 1799, where HP is the engine's horsepower output rating. For annual operating costs, the following equation was determined: NSCR Annual Cost = 2.65 * HP + 657, where HP is the engine's horsepower output rating. For additional information see:
<http://www.regulations.gov#!documentDetail;D=EPA-HQ-OAR-2005-0030-0005>

In 2007 the Illinois Environmental Protection Agency prepared its "Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines". This document reviewed NOx emissions control capabilities and estimated cost effectiveness for a number of NOx controls for rich burn reciprocating engines. Included in this evaluation for rich burn engines is the application of NSCR for NOx control. The document indicates that NSCR has the capability of reducing NOx emissions from rich burn engines by approximately 90% to 98%. The following summarizes the rich burn engine NSCR evaluation:

Type of Control	Nameplate Rating (HP)	Total Capital Cost (2004 \$)	Cost Effectiveness (2004 \$/ton)
Rich Burn NSCR	500 – 8,000	35,400 – 330,700	319 – 1,647

For additional information see: <http://www.epa.state.il.us/air/rules/rice/tsd-rice.pdf>

In support of its development of Rule 4702, Internal Combustion Engines Phase 2, in 2003 the San Joaquin Valley Air Pollution Control District prepared a cost effectiveness analysis for the retrofit installation of NSCR on rich burn spark ignited internal combustion engines. The analysis was performed for a range of engine output ratings. The analysis assumed the installation would achieve compliance with a proposed NOx emissions rate limit of 25 ppmvd @15% O2 (approximately 0.37 g/bhp-hr). The results of the analysis for rich burn spark ignition engines is summarized below:

Rich Burn Engine NSCR NOx Reduction Control Installation Cost Estimation					
Nameplate Rating (hp)	NSCR Installed Cost (\$)	Annual O&M Cost (\$)	Annualized Cost (\$)	25% Cap Fact Cost Effectiveness (\$/ton)	75% Cap Fact Cost Effectiveness (\$/ton)
50	13500	7199	9395	8415	2829
200	18500	7819	10829	2446	815
500	20500	8819	12154	1098	366
1000	30500	11319	16281	735	245
1500	47000	18919	26566	800	267

Note: Annualized cost based on 10 year life and 10% interest.

NOx reductions based on 9.55 g/bhp-hr pre-installation and 0.37 g/bhp-hr post-installation.

For additional information see:

http://www.arb.ca.gov/pm/pmmeasures/ceffect/reports/sjvapcd_4702_report.pdf

4.3.5 Four Stroke Rich Burn Spark Ignition Engine NOx Control Summary

Industry information indicates that there are technically feasible, commercially available NOx reduction technologies applicable to natural gas fired, spark ignited, rich burn engines. The information suggests that there are a few combustion related NOx emissions control applicable to these rich burn engines, such as installation of EGR, improved induction and fuel delivery, modification for lean burn operation, etc. However, such modifications may not be feasible for retrofit for all subject rich burn engines due to unavailability of the required components or extraordinarily high costs to make the conversions. The industry information also indicates that there are technically feasible, commercially available post-combustion (NSCR) NOx reduction systems available for use on virtually the entire range of nameplate ratings and make/model variability of the four stroke rich burn spark ignition reciprocating engines.

From the industry information it appears that the actual achievable NOx emission rate, in terms of g/bhp-hr, achievable from installation of NSCR tends to be engine design specific. However, it appears that commercially proven NSCR NOx reduction technologies are widely available from engine original equipment manufacturer (OEM) companies as well as aftermarket suppliers that can be expected to achieve NOx reductions of 90% or greater. While there may be a few engine specific or site specific installation or operational problems that could impact NSCR performance, there appears to be little industry information that documents such issues. Any potential engine design or site specific issues could generally be addressed by providing appropriate flexibility in any rulemaking that includes consideration of site specific issues.

The information therefore seems to support NOx emission rate limits of 0.2-0.5 g/bhp-hr for many four-stroke rich burn spark ignition reciprocating engines with a nameplate rating of 50 hp or above, providing that there is consideration of individual engine design and site specific flexibility provisions. Engine specific and site specific issues could be addressed with appropriate rule or regulation flexibility of consideration of individual engine design and site specific flexibility provisions.

The installation of NSCR on both a new and retrofit basis for rich burn engines has been a widespread practice for a considerable time, and should be considered a relatively mature process. While capital costs would be somewhat site specific, industry literature indicates that for the majority of installations the capital costs are primarily a function of the rich burn engine's nameplate rating.

Type of NOx Control	Engine Size Range (hp)	Estimated Range of NOx Reduction	Estimated Range of NOx Emissions Rate	NOx Control Estimated Costs (\$)
		(%)	(g/bhp-hr)	
Retrofit NSCR	50 - 2000	99	0.2 - 0.5	16,700 - 363,000
New Unit w/NSCR	50 - 2000	N/A	0.15	N/A

(Note: Estimated control costs are initial capital cost estimates only. Costs are based on Illinois' "Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines", adjusted for CPI.)

It should be noted that the range of costs for installation of NSCR on four stroke rich burn spark ignition reciprocating engines is primarily a function of the nameplate rating of the engine. However, variability may exist due to site specific conditions and complexity of installation of an air/fuel ratio controller. Also, the cost effectiveness (in terms of \$/tons of NO_x reduced) will depend upon the operational characteristics (capacity factor) of the affected engine.

4.4 Reciprocating Engines - Diesel Engines

In a reciprocating engine, combustion of a compressed fuel-air mixture is used to drive pistons in one or more cylinders, with the linear piston motion converted to rotary motion with a crankshaft. The rotary motion developed by the reciprocating engine may then be utilized to drive natural gas compressors, pumps, mechanical drives, or other rotary loads. Compression ignition engines utilize the heat generated during relatively high levels of compression of the combustion air in the combustion chamber to cause ignition of the fuel air mixture when the fuel is introduced into the combustion chamber. Diesel engines may be either two-stroke or four-stroke.

In a diesel engine, combustion air is drawn into the cylinder and compressed in the combustion chamber with a relatively high compression ratio compared to most spark ignition engines. As a result of the compression, the combustion air temperature is raised to a high level, often 1300 degF to 1650 degF. With the piston at or near the top of the compression stroke, diesel fuel is injected into the combustion chamber through an atomizing fuel nozzle, mixing the fuel with the hot combustion air. The fuel air mixture ignites as a result of the high temperature in the combustion chamber. The expanding combustion products push down on the piston and connecting rod, which transfers this motion to the crankshaft, resulting in rotary motion and engine output power. The inlet of combustion air and exhaust of spent combustion products occurs through ports or valves in the cylinder heads. To further improve the output and efficiency of a diesel engine, turbochargers are often utilized to compress the combustion air prior to entry into the cylinder and attaining a high level of cylinder filling and pressure. The use of air coolers between the air outlet of the turbocharger and the cylinder inlet cools the combustion air and helps further improve the engine efficiency.

Diesel engines may be either 2 stroke or 4 stroke configurations, with the majority being 4 stroke and some large units being 2 stroke. Diesel engines are lean burn engines.

There are various diesel engine manufacturers, with most manufacturing multiple models with a range of rated outputs.

4.4.1 Diesel Engine NOx Controls

One potential method to achieve modest NOx emissions reductions from diesel engines is the appropriate setting of the fuel injection timing. Control of the start of fuel injection timing, relative to the crankshaft angle of top-dead-center for the specific cylinder, can affect the diesel engine's efficiency and NOx emissions, depending upon engine design and load. Advancing the fuel injection timing, relative to the cylinder's compression top dead center, will tend to improve the engines efficiency and result in higher NOx emissions. Retarding the injection timing, relative to the cylinder's compression top dead center, will tend to reduce NOx emissions but also reduced the engine's efficiency, possibly increasing the engine's particulate emissions. The amount of effective control is highly dependent upon the engine design and operating characteristics. While this NOx reduction technology is applicable to nearly any diesel engine, its effectiveness is likely greatest on older, otherwise uncontrolled, diesel engines. Industry literature suggests that NOx reductions of up to 20% to 25% may be possible utilizing diesel injection timing retard, with a 10% reduction being more common.

Another potential method to achieve modest diesel engine NOx emissions reductions is the use of emulsified fuels. Emulsified diesel fuel is a blended mixture of diesel fuel, water and other additives.

The water is suspended in droplets within the fuel, creating a cooling effect in the combustion chamber that decreases NOx emissions. A fuel-water emulsion creates a leaner fuel environment in the engine, lowering NOx and PM emissions. Emulsified diesel can be used in any diesel engine, but there is a decrease in power and fuel economy due to the fact that the addition of water reduces fuel energy content. Emulsified fuel can achieve emission reduction of NOx by about 10 to 20 percent and PM by about 50 to 60 percent.

The use of exhaust gas recirculation (EGR) is an effective NOx control for diesel engines in new and retrofit applications. Both low-pressure and high-pressure EGR systems exist but low-pressure EGR is used for retrofit applications because it does not require engine modifications. EGR involves recirculating a portion of the engine's exhaust gas back to the turbocharger inlet or intake manifold, in the case of a naturally aspirated engines. In most systems, an intercooler lowers the temperature of the recirculated exhaust gas. The cooled recirculated exhaust gas mixed in with the combustion air tends to result in an overall lower combustion temperature in the engine, thus inhibiting NOx formation. Diesel particulate filters are always used with a low-pressure EGR system to ensure that large amounts of particulate matter are not recirculated to the engine. EGR systems are capable of achieving NOx reductions of more than 40 percent in both new and retrofit applications.

Selective catalytic reduction (SCR) is a post-combustion NOx control applicable to diesel engines that utilizes a catalyst and a reducing agent to reduce the concentration of NOx in the exiting combustion gasses. The reagent, typically ammonia or urea, is injected into the exhaust stream of the engine. Once in the exhaust, the ammonia (or urea that decomposes to produce ammonia in the exhaust stream) passes over a catalyst to help convert the NOx, hydrocarbons and CO into water, nitrogen and CO₂. Catalyst selection is somewhat based on the expected temperature range of the engine exhaust, and is sized to achieve the desired amount of NOx reduction. The reagent injection system is comprised of a storage tank, reagent injector(s), reagent pump, pressure regulator and electronic controls to accurately meter the quantity of reagent injected as a function of engine load, speed, temperature and NOx emissions. Industry information indicates that the use of SCR for NOx control may facilitate NOx reductions of up to 95%, although 75% to 90% reduction is more typical. Industry information indicates that there are a number of suppliers of SCR systems for diesel engines, and many systems have been installed and are successfully in commercial operation. SCR may be utilized in either a new or retrofit application.

Industry information indicates that there are additional NOx reduction technologies applicable to diesel engines. One technology, lean NOx catalyst systems, utilize injection of a small amount of fuel into the exhaust to act as a reductant in conjunction with a zeolite catalyst to attain NOx reductions of 10% to 50%. Another, lean NOx traps, traps NOx in a barium hydroxide or barium carbonate material during normal engine lean operation, and engine controls periodically cause the engine to operate fuel rich mode to regenerate the trap material and release the NOx as N₂ or NH₃. Industry information indicates that lean NOx traps may be able to reduce NOx emissions by as much as 90%. No information was found regarding commercial operation of either of these technologies in the field, so they are not considered to be commercially available diesel engine NOx reduction technologies for the purposes of this review.

<u>Compression Ignition Engine NOx Control Retrofit Technology</u>	<u>Potential NOx Reduction</u>
Fuel Injection Timing	10%
Emulsified Fuel	10% - 20%
Exhaust Gas Recirculation	40% - 50%
Selective Catalytic Reduction	75% - 90%

4.4.2 Example Existing Rules and Regulations – Diesel Engines

California - California's South Coast Air Quality Management District (SCAQMD) has established Rule 1110.2, Emissions from Gaseous and Liquid Fueled Engines, the latest revision of the rule dated July 2010. Rule 1110.2 regulates NOx emissions from new and existing stationary spark or compression ignition internal combustion engines with a nameplate rating of 50 hp or greater. (This rule, 1110.2, may be accessed from <http://aqmd.gov/rules/download.html>)

NOx emission limits noted in SCAQMD Rule 1110.2 applicable to existing stationary spark and compression ignition engines include:

Nameplate - Bhp $\geq$ 500	36 ppmvd NOx (<i>approximately 0.5 g/bhp-hr</i>)
Nameplate - Bhp<500	45 ppmvd NOx (<i>approximately 0.6 g/bhp-hr</i>)
Effective July 1, 2010	
Nameplate - Bhp $\geq$ 500	11 ppmvd NOx (<i>approximately 0.15 g/bhp-hr</i>)
Nameplate - Bhp<500	45 ppmvd NOx (<i>approximately 0.6 g/bhp-hr</i>)
Effective July 1, 2011	
Nameplate - All	11 ppmvd NOx (<i>approximately 0.15 g/bhp-hr</i>)

(Note that SCAQMD Rule 1110.2 contains exemptions for units that operate less than 500 hrs/yr or burn less than 100 MMBTU/yr.) (Note that the rule makes no distinction for rich burn, lean burn, etc stationary engines.)

California - California's San Joaquin Valley Air Pollution Control District's Rule 4702, Internal Combustion Engines, amended August 18, 2011, regulates NOx emissions from stationary spark and compression ignition engines with nameplate ratings of 25 hp and greater. (This rule may be viewed at <http://www.arb.ca.gov/DRDB/SJU/CURHTML/R4702.PDF>)

The NOx emissions limits noted in the San Joaquin Valley Air Pollution Control District's Rule 4702 for non-certified compression ignition engines, installed on or before June 1, 2006, and with nameplate ratings of greater than 50 hp include:

50 < HP $\leq$ 500	EPA Tier 3 or Tier 4
500 < HP $\leq$ 750 and less than 1000 hrs/yr operation	EPA Tier 3
HP > 750 and less than 1000 hrs/yr operation	EPA Tier 4
HP > 500 and 1000 hrs/yr or more operation	80 ppmvd NOx

The USEPA has established NO_x emissions limitations for new compression ignition engines, and those limitations vary with the manufacture date of the subject engines. For example 40 CFR Part 60, Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, requires that the owners and operators of pre-2007 model year non-emergency stationary compression ignition engines with a displacement of less than 10 liters per cylinder comply with the following NO_x emission standards:

Maximum Engine Power HP<11 11≤HP<25 25≤HP<50 50≤HP<75 75≤HP<100 100≤HP<175 175≤HP<300 300≤HP<600 600≤HP≤750 HP>750	Emission standards or stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007 -2010 model year engines > 3000 HP and with a displacement of <10 liters per cylinder (g/HP-hr)
	6.9
	6.9
	6.9
	6.9
	6.9
	6.9
	6.9
	6.9

NO_x emissions standards for 2011 and beyond compression ignition engines are identified in 40 CFR Part 1039—Control Of Emissions From New And In-Use Nonroad Compression-Ignition Engines, as shown in the following table:

Maximum engine power	NO _x
kW < 19	
19 ≤ kW < 56	
56 ≤ kW < 130	0.4
130 ≤ kW ≤ 560	0.4
kW > 560	3.5

(Note: Nox emissions limits in above table are in g/kw-hr)

4.4.3 Discussion of Diesel Engine NOx Reduction Capability – Combustion Modifications

The use of emulsified fuels is accomplished by using surfactant additives to encapsulate water droplets in diesel fuel to form a stable mixture while ensuring that the water does not contact metal engine parts. Firing emulsified fuels in diesel engines tends to reduce peak engine combustion temperatures and increase fuel atomization and combustion efficiency. However, the use of the emulsified fuels also tends to result in an approximate 20% reduction in peak engine output. Emulsified fuels are expected to have an approximate 15% cost penalty compared to traditional diesel fuel costs. The low NOx reduction capability of this technology, along with the relatively large impact on engine output, make the use of emulsified fuels an unlikely standalone technology for use in diesel engine NOx reduction.

Exhaust gas recirculation (EGR) is an available NOx reduction technology applicable to diesel engines. Some original equipment manufacturer (OEM) diesel engines are currently being marketed with EGR as original equipment. There are also some suppliers of retrofit EGR systems for existing diesel engines. There is little information concerning the availability of such retrofits for the wide range of diesel engine makes and models. Any EGR system would likely require a custom design for each make and model, with potential further customization required for site specific conditions. Some of the industry information indicates that low sulfur fuels and particulate traps are required with the retrofit of EGR systems to help maintain system performance and to limit additional wear on engine components and contamination of lube oil. The industry information indicates that the use of EGR can achieve NOx reductions of from 40% to 50%. The information also indicates that the use of EGR can result in an approximate 2% loss in fuel efficiency and a loss of approximately 2% in engine output capability, dependent upon the amount of exhaust gas recirculated. No specific cost estimates were found regarding the retrofit of EGR on existing diesel engines. However, one source suggested a potential retrofit capital cost of \$500 to \$700 per engine rated horsepower.

4.4.4 Discussion of Diesel Engine NOx Reduction Capability – Post Combustion Modifications

The post-combustion control selective catalytic reduction (SCR) is the process where a reductant (typically ammonia or urea) is added to the flue gas stream and is absorbed onto the catalyst (typically vanadium or zeolite) enabling the chemical reduction of NOx to molecular nitrogen and water. Diesel engines typically have unconsumed oxygen in the exhaust, which inhibits removal of oxygen from the NOx molecules. To remove the unconsumed oxygen, the catalyst decomposes the reductant causing the release of hydrogen, which reacts with the oxygen. This creates local oxygen depletion near the catalyst allowing the hydrogen to also react with the NOx molecules to form nitrogen and water.

A number of information sources discuss diesel engine applicable SCR systems and the performance of some installation examples, including the following:

- A presentation by Shell indicated that Shell has been installing SCR NOx reduction systems on diesel engines used to support drilling rig operations. Shell's information indicated that Shell has observed NOx reductions of greater than 90% in this application with minimal impact on operations. This project is further documented in an application fact sheet from Johnson Matthey Catalysts, "Case No. 801: Controlling NOx From Gas Drilling Rig Engines With Johnson Matthey's

Urea SCR System” . For the project, Johnson Matthey provided urea SCR systems for three 1476 hp Caterpillar 3512 BDITA diesel engines. Johnson Matthey indicated that the supplied SCR systems were designed to operate in harsh environmental conditions and with the dramatic engine load swings associated with drilling operations. Johnson Matthey indicated that they met the 90% NOx emissions reduction requirements, actually achieving NOx reductions between 91% and 99%. For additional information see: <http://ect.jmcatalysts.com/pdfs-library/Application%20Fact%20Sheet%20801%20-%20Shell%20Gas%20Drill%20Rig.pdf>

- Johnson Matthey markets urea based SCR systems that reduce NOx emissions from diesel engines by 90% or more. Johnson Matthey offers catalysts with a broad effective operating temperature range to achieve NOx reductions earlier in an engine operating cycle and across a wide engine operating range. For additional information see: <http://ect.jmcatalysts.com/site.asp?siteid=836&pageid=888&furtherid=946>
- CleanAir Systems offers a SCR system that they advertise as being applicable to diesel engines. CleanAir indicates that their SCR catalyst allows NOx reduction operation in a wide range of temperatures, from approximately 300 degF to approximately 1000 degF. (CleanAir Systems was acquired by Caterpillar in 2010, and is now called CleanAir Systems, A Caterpillar Company.) Their diesel engine SCR product is now being referred to as E-Pod SCR. CleanAir indicates that their diesel engine capable SCR achieves up to 95% reduction in NOx emissions across a wide range of exhaust temperatures. For additional information see: <http://www.cleanairsys.com/products/hybrids/index.htm>
- Miratech Corporation offers a SCR based NOx reduction system that is advertised to be applicable to diesel engines. Miratech indicates that NOx reductions of up to 99% are achievable with their SCR system. For additional information see: http://www.miratechcorp.com/images/data/attachments/0000/0019/SCR_Systems.pdf
- Wartsila offers a retrofit SCR NOx reduction system for diesel engines. Wartsila indicates that their product is scalable to meet the needs of various engine size/needs and may be provided as a skid-based system. Wartsila specifically targets the oil/gas industry for this system, most specifically for drilling rig operations. Wartsila indicates that their SCR system can attain 85% to 95% reduction in NOx emissions. For additional information see: <http://wartsila.com/en/environmental-technologies/air-emissions-control/NOR>
- A Combustion Components Associates Inc. technical bulletin describes a project involving the installation of SCR systems on four new Caterpillar 3516 2.5MW diesel engines. The SCR systems were designed to eliminate the need for compressed air in atomizing the urea, and achieved NOx reductions of over 90%. The bulletin indicates that the SCR systems allowed the engines to achieve NOx emissions rates below the 0.6 g/bhp-hr across an operating load range of 25% to 100% load. For additional information see: http://combustioncomponents.com/downloads/Technical_Bulletin_2009-001.pdf
- A Combustion Components Associates Inc. technical bulletin describes a project involving the installation of SCR systems on four existing General Motors EMD two-stroke V-16 2100kw diesel engines. The SCR systems were designed to achieve a NOx emissions rate limit of 2.3 g/bhp-hr which represented an approximate 73% reduction from the uncontrolled emissions rate.

For additional information see:

(http://combustioncomponents.com/downloads/BL_England_Case_Study.pdf)

In 2007 the Illinois Environmental Protection Agency prepared its “Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines”. This document reviewed NOx emissions control capabilities and estimated cost effectiveness for a number of NOx controls for diesel reciprocating engines. Included in this evaluation for diesel engines is the application of SCR for NOx control. The document indicates that SCR has the capability of reducing NOx emissions from diesel engines by approximately 80% to 90%. The following summarizes the diesel engine SCR evaluation:

<u>Type of Control</u>	<u>Nameplate Rating</u> (HP)	<u>Total Capital Cost</u> (2004 \$)	<u>Cost Effectiveness</u> (2004 \$/ton)
Diesel SCR	500 - 8000	308,500 – 1,264,100	899 – 4,536

For additional information see: <http://www.epa.state.il.us/air/rules/rice/tsd-rice.pdf>

In its “Alternative Controls Techniques Document: Stationary Diesel Engines”, the EPA provided estimated costs for the installation of SCR on diesel engines. In the document, the EPA states that the capital costs for diesel EGR are approximately \$98 per rated horsepower, including the catalyst, reactor housing and ductwork, ammonia injection system, controls, engineering, and installation. The following table summarizes the EPA’s estimates presented in the document:

Diesel Engine Nameplate Rating (hp)	Estimated Capital Cost (2009\$)
75 – 100	7,350
175 – 300	23,324
600 – 750	66,150
>750	98,000

For additional information see: http://www.epa.gov/ttn/atw/rice/diesel_eng_act.pdf

4.4.5 Diesel Engine NOx Control Summary

Industry information indicates that there are several available NOx reduction technologies applicable to diesel engines. Some combustion related NOx reduction technologies offer only low levels of NOx reduction, e.g. injection timing (~ 10% reduction), emulsified fuel (10% to 20% reduction). Another combustion related diesel engine NOx reduction technology, exhaust gas recirculation (EGR), is reported to be capable of moderate levels of NOx reduction (40% to 50%), but has had limited retrofit application to date. Because of the limited NOx reduction capabilities of these technologies and apparent limited commercial availability of the technologies, at this time these combustion related technologies are not considered primary NOx reduction technologies for use in diesel engine retrofit. This could change in the future as the technologies become more developed and more widely commercially available.

The industry information indicates that post-combustion controls are also applicable to diesel engines for NOx reduction. The available information describes NOx traps and NOx absorbers for diesel engine

applications, but no examples of commercial application of these technologies on diesel engines could be found at the time of preparation of this document. In contrast, SCR is a post combustion NOx reduction technology applicable to diesel engines, it is commercially available from several suppliers, and has been in commercial operation on diesel engines for some time. Some examples of existing installation of SCR on diesel engines include the use of diesel to drive electric generators in base, intermediate, and peak operating modes and for use on diesel generators utilized to power drilling rigs (variable operation). Industry information indicates the SCR can achieve NOx reductions from diesel engines in the range of 75% to 90%.

Based on the available information, it appears that a properly sized and engineered SCR system is the only currently commercially available NOx emission control for diesel engines with the capability of achieving up to 90% control of NOx emissions.

<u>NOx Reduction Technology</u>	<u>Nameplate Rating (hp)</u>	<u>Estimate Range of Controlled NOx (%)</u>	<u>Estimated Cost (\$)</u>
SCR	500 - 8000	75 – 90	371,700 – 1,523,200

(Note: Estimated control costs are initial capital cost estimates only. Costs are based on Illinois' "Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines", adjusted for CPI.)

It should be noted that the range of costs for installation of SCR on diesel reciprocating engines is primarily a function of the nameplate rating of the engine. However, variability may exist due to site specific conditions and complexity of installation. Also, the cost effectiveness (in terms of \$/tons of NOx reduced) will depend upon the operational characteristics (capacity factor) of the affected engine.

4.5 Combustion Turbines

Combustion turbines have three main sections; the compressor, the combustor, and the power turbine. The compressor draws in and pressurizes ambient air. In the combustor, fuel is mixed and combusted with a portion of the compressed air. The resulting combustion gases are diluted with the remainder of the air from the compressor to create a large volume of a hot, compressed combustion gas mixture. The hot, compressed gases then expand in the turbine section, driving the power turbine and creating the turbine's output rotary motion. The rotating turbine shaft is connected to the driven load, sometimes through a gear box.

There are several different manufacturers of combustion turbines, and each manufacturer generally has multiple combustion turbine models that represent a wide range of combustion turbine output ratings.

4.5.1 Combustion Turbine NO_x Controls

There are a number of commercially available NO_x reduction technologies for combustion turbines, but not all may be applicable or available for any given make/model of combustion turbine.

Water injection is a NO_x reduction technology applicable to most combustion turbines. Injecting water into the combustion zone tends to lower peak flame temperatures, thereby lowering the amount of thermal NO_x formation during combustion. Water may be injected directly into the turbine combustor, or may be converted to steam using turbine exhaust waste heat with a heat recovery steam generator (HRSG), and then injected into the combustor as steam. More steam than water must be used to achieve a comparable NO_x reduction, but the use of steam may result in a lower energy penalty than use of water if the turbine's waste heat would not otherwise be recovered and used. Depending upon the make/model of the applicable combustion turbine, turbine modifications may be as simple as replacement of fuel nozzles with nozzles capable of supplying fuel and water/steam (and associated plumbing), or may be as complex as requiring replacement of the combustors designed to operate with water/steam injection (and associated plumbing). Other required equipment would include appropriate combustion turbine control systems, a source of demineralized water (onsite water plant with storage, or storage tank for demineralized water prepared offsite), a water injection pump, and a water/steam flow metering station. Industry literature indicates that water/steam injection can result in combustion turbine NO_x emissions reductions of 40% or more.

The use of dry low NO_x burners (DLNB) is a NO_x emissions reduction technology available for many makes and models of combustion turbines. DLNB technology utilizes a lean, premixed flame in the combustor as opposed to a turbulent diffusion flame. In a lean, premixed combustor, the fuel and air are premixed prior to entering the combustion zone. With a lean, premixed flame, the contribution of prompt and thermal NO_x can be much lower than for a turbulent diffusion flame that is typical for non-DLNB combustion turbine combustors. Many DLNB combustors are capable of achieving NO_x emissions reductions across the full load range, but some require more sophistication to allow variable operating modes in order to maintain flame stability across the full load range. Not all turbine designs can accommodate a DLNB, and DLNB combustors may not be available for all makes and models of combustion turbines. In addition to the replacement of the turbine's combustors, installation of DLNB technology may require modifications or replacement of associated piping and turbine combustion control modification or replacement. Industry literature indicates that the retrofit utilization of DLNB

technology can achieve NOx reductions of 60% or more for those units where the technology is available.

Selective catalytic reduction (SCR) is a NOx reduction technology applicable to combustion turbines. SCR is a post-combustion NOx control that utilizes a catalyst and a reducing agent to reduce the concentration of NOx in the exiting combustion gasses. The reagent, typically ammonia or urea, is injected into the exhaust stream of the combustion turbine. Once in the exhaust, the ammonia (or urea that decomposes to produce ammonia in the exhaust stream) passes over a catalyst to help convert the NOx, hydrocarbons, and CO into water, nitrogen and CO2. Catalyst selection is somewhat based on the expected temperature range of the combustion turbine exhaust, and is sized to achieve the desired amount of NOx reduction. The reagent injection system is comprised of a storage tank, reagent injector(s), a reagent pump, pressure regulator and electronic controls to accurately meter the quantity of reagent injected as a function of combustion turbine load, temperature and NOx emissions. Industry information indicates that the use of SCR for NOx control on combustion turbines may facilitate NOx reductions of 95% or more.

<u>Combustion Turbine NOx Control Technology</u>	<u>Potential NOx Reduction</u>
Water Injection	40%
Dry Low NOx Burners (DLNB)	60%
SCR	95%

4.5.2 Example Existing Rules and Regulations - Combustion Turbines

California - California's South Coast Air Quality Management District (SCAQMD) has established Rule 1134, EMISSIONS OF OXIDES OF NITROGEN FROM STATIONARY GAS TURBINES, that provides NOx emissions limitations for combustion turbines. (This rule may be viewed at <http://aqmd.gov/rules/reg/reg11/r1134.pdf>)

Rule 1134 provides an equation that is used to determine the NOx emissions limitations for various sizes of combustion turbines. The equation is:

$$\text{Compliance Limit} = \text{Reference Limit} \times (\text{EFF}/25\%)$$

Where Compliance Limit = NOx emissions limit (ppmvd@15% O2)
 EFF = Thermal efficiency (%)
 Reference Limit = NOx rate (ppmvd) from following table

<u>Nameplate Rating</u>	<u>Ref. NOx Limit (ppmvd)</u>
0.3 to Less Than 2.9 MW	25
2.9 to Less Than 10.0 MW	9
2.9 to Less Than 10.0 MW No SCR	15
10.0 MW and Over	9
10.0 MW and Over No SCR	12

Texas - The Texas Commission on Environmental Quality revised its permit by rule (revision date February 17, 2012) for the oil and gas industry sources in Texas, §106.352 Oil and Gas Handling and Production Facilities. The Texas rule provides NOx emissions limitations for the various types of oil and gas sector sources, including NOx emissions limitations for combustion turbines. The relevant emissions limitation in the rule includes the following:

Combustion Turbine 25 ppmvd@15% O2

Additionally, Texas Administrative Code, Combustion Control at Major Industrial, Commercial, and Institutional Sources in Ozone Non-Attainment Areas, Beaumont-Port Arthur Ozone NonAttainment Area Major Sources, Rule §117.105, Emission Specifications for Reasonably Available Control Technology (RACT), provides NOx emissions limitations for combustion turbines as follows:

Combustion Turbine > 10.0 MW 42 ppmv @ 15% O2

Pennsylvania has recently proposed a revision to its General Permit for Natural Gas Production and Processing Facilities (GP-5). The proposed GP-5 will apply to simple cycle combustion turbines and other air contamination sources at natural gas production and processing facilities. When the currently proposed GP-5 becomes effective, new and reconstructed simple cycle combustion turbines with a nameplate rating greater than or equal to 1000 hp will be required to comply with a NOx emissions rate limit of 15 ppm @ 15% O2.

USEPA - The USEPA established NOx emissions limitations for combustion turbines in 40 CFR Part 60, Subpart KKKK (NSPS) (7/6/06 71 FR 38482) applicable to natural gas-fueled combustion turbines are summarized in the following table:

Combustion Turbine Type	Peak Load Heat Input	NOx Limit
New turbine firing natural gas, electric generating	≤ 50 MMBtu/h	42 ppm at 15 percent O ₂ or 290 ng/J of useful output (2.3 lb/MWh).
New turbine firing natural gas, mechanical drive	≤ 50 MMBtu/h	100 ppm at 15 percent O ₂ or 690 ng/J of useful output (5.5 lb/MWh).

New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O ₂ or 150 ng/J of useful output (1.2 lb/MWh).
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/h	15 ppm at 15 percent O ₂ or 54 ng/J of useful output (0.43 lb/MWh)
New turbine firing fuels other than natural gas, electric generating	≤ 50 MMBtu/h	96 ppm at 15 percent O ₂ or 700 ng/J of useful output (5.5 lb/MWh).
New turbine firing fuels other than natural gas, mechanical drive	≤ 50 MMBtu/h	150 ppm at 15 percent O ₂ or 1,100 ng/J of useful output (8.7 lb/MWh).
New turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	74 ppm at 15 percent O ₂ or 460 ng/J of useful output (3.6 lb/MWh).
New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/h	42 ppm at 15 percent O ₂ or 160 ng/J of useful output (1.3 lb/MWh).
Modified or reconstructed turbine	≤ 50 MMBtu/h	150 ppm at 15 percent O ₂ or 1,100 ng/J of useful output (8.7 lb/MWh).
Modified or reconstructed turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O ₂ or 250 ng/J of useful output (2.0 lb/MWh).
Modified or reconstructed turbine firing fuels other than natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	96 ppm at 15 percent O ₂ or 590 ng/J of useful output (4.7 lb/MWh).

4.5.3 Combustion Turbine NOx Reduction Combustion Controls

The literature suggests that the combustion related NOx reduction technologies of water injection and dry low NOx burners (DLNB) are commercially available NOx reduction technologies for combustion turbines that are capable of achieving NOx reductions of 40% and 60%, or greater, respectively. Although there appears to be both OEM and aftermarket suppliers of these NOx reduction technologies for combustion turbines, the literature indicates that these NOx reduction technologies may not be commercially available for all makes and models of combustion turbines, more so for the relatively small size of combustion turbine representative of industrial utilization.

Some of the combustion turbine manufacturers offer a version of low NOx burners for many of their particular models of combustion turbine, some as original equipment and some as retrofit, as follows:

- Capstone markets a new natural gas fueled combustion microturbine, turbine generator with a 1 MW electrical rating. Capstone indicates that the NOx emissions from this turbine generator are less than 9 ppmvd in standard version and less than 4 ppmvd in CARB version. For additional information see: <http://www.microturbine.de/uploads/File/C1000%20HPNG.pdf>
- GE offers retrofit dry low NOx emissions systems for many of their combustion turbines. Dependent upon the model of the combustion turbine (technology/product may not be available for all models), GE offers low NOx burner systems that may result in NOx emissions levels in the single digit ppmvd range. For certain models, GE offers dry low NOx emissions systems along with water injection for further NOx emissions reductions. For additional information see: http://www.ge-energy.com/products_and_services/industries/oil_and_gas_upstream.jsp
- Solar Turbines information indicates that Solar offers an extensive line of standard NOx reduction retrofit kits for most of the Solar gas turbine product line, including their low-NOx SoLoNOx gas fuel system upgrade to achieve NOx emissions reductions. Solar also offers its SoLoNOx emissions reduction technology for many of its currently offered gas turbine models. For additional information see: <http://mysolar.cat.com/cda/layout?m=35881&x=7>
- A paper presented by Alstom described a project to achieve low NOx emissions from an Alstom GT10 combustion turbine, with an approximate 23 MW nameplate rating. The paper indicates that this series of combustion turbine was originally intended to drive compressors, but was being used for cogeneration in this particular application. The NOx control system used a combination of low-NOx combustor design and water injection to meet a 15 ppmvd NOx emissions limit over a wide range of operating and ambient conditions. The paper indicated that the combustion turbine outlet NOx emissions were generally held to 10 ppmvd. For additional information see: <http://cogen.mit.edu/files/powergen.pdf>

Similarly, the literature suggests that the cost for combustion related and post combustion NOx emissions controls vary greatly with the make and model of the combustion turbine. For example, in a 1999 document, Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines, the following capital cost estimates were prepared for presentation to the US Department of Energy:

Make/Model	Rating (approximate) (MW)	Water Injection Capital Cost (\$)	DLN Capital Cost (\$)	Hi-Temp SCR Capital Cost (\$)
GE LM2500	23	1,083,175	800,000	1,269,324
GE 7FA	170		4,500,000	5,216,400
Solar Centaur 50	4.2	405,500	190,000	
Allison 501-KB5	4	291,000	20,000	
Solar Taurus 60	5		190,000	652,050

Note: The above costs are in 1999 \$.

The DLN capital costs are incremental costs compared to conventional burners.

For additional information see:

http://www1.eere.energy.gov/industry/distributedenergy/pdfs/gas_turbines_nox_cost_analysis.pdf

4.5.4 Combustion Turbine NOx Reduction Post Combustion Controls

The post combustion NOx reduction technology SCR appears to be a technically feasible NOx reduction technology for many combustion turbines, and systems appear to be commercially available for simple cycle combustion turbines. However, industry representatives have raised several issues questioning the applicability of SCR to combustion turbines driving natural gas compressors.

One industry stated issue concerned with the use of SCR for combustion turbines is that many related facilities are unmanned and that SCR installations have not been demonstrated in un-manned facilities. Other industry information indicates that while it may be true that there are currently few SCRs in unmanned facilities, with modern software based controls and supervisory control and data acquisition (SCADA) type communication technologies there does not appear to be any technical barrier to operating the SCR related controls and auxiliaries successfully from a remote location.

Industry sources have also stated that SCRs have not been demonstrated on combustion devices with variable loads. SCR manufacturers offer catalysts that are effective over wide temperature ranges characteristic of a range in combustion turbine operating load. Modern controls also have the ability to closely regulate fuel and air flows to ensure combustion gas oxygen and temperature levels at expected levels and to regulate reagent flow, all serving to ensure proper SCR function over a broad range of load.

Several organizations market SCR systems applicable to combustion turbines. A summary of some of the marketed systems are summarized below:

- Johnson Matthey markets SCR systems for combustion turbines, and indicates that they have supplied SCR systems for combustion turbines with output ratings ranging from 3MW to greater than 200MW. Johnson Matthey indicates that they can engineer the systems to work with natural gas fuel, diesel fuel, or co-fired natural gas and diesel. Johnson Matthey states that their SCR systems are designed to have a rapid startup capability, permitting the combustion turbine to come in compliance with NOx emission limits within minutes of startup. The Johnson Matthey SCR

systems for combustion turbines are capable of achieving NOx reductions in excess of 95%, and attaining NOx emission rates below 2 ppm. For additional information see:

<http://ect.jmcatalysts.com/emission-control-technologies-gas-turbines>

- Nationwide Environmental Solutions offers their CataStak SCR NOx reduction systems for combustion turbines, delivering reliable NOx emissions as low as 2.5 ppm @ 15% O2. Nationwide Environmental Solution's literature indicates that they offer SCR systems for combustion turbines sized down to an output rating of 0.5 MW, and with a combustion gas exhaust temperature of up to 1000 degF. The Nationwide Environmental Solution's information also indicates that their design includes simple controls, requires minimal operator intervention (Auto Start/Stop) and is easy to retrofit on existing equipment (vertical or horizontal arrangements). For additional information see: For additional information see: http://www.catastak.com/catastak_gt/index.html
- Turner EnviroLogic offers SCR systems for simple cycle combustion turbines that are designed to integrate with the combustion turbine controls to provide operation with little to no operator attention. The design is intended to facilitate efficient, reliable operation with the frequent start/stop cycling typical of the operation of many simple cycle combustion turbines. The document also indicates that the SCR systems and components can be custom designed to accommodate site specific installation requirements. For additional information see: http://equipmentsourceco.com/pdf/scr_systems.pdf

In 2007 the Illinois Environmental Protection Agency prepared its "Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines". This document reviewed NOx emissions control capabilities and estimated cost effectiveness for a number of NOx controls for reciprocating engines and combustion turbines. Included in this evaluation for combustion turbines is the application of SCR for NOx control. The document indicates that SCR has the capability of reducing NOx emissions from combustion turbines by approximately 90%. The following summarizes the combustion turbine SCR evaluation:

<u>Type of Control</u>	<u>Nameplate Rating (MW)</u>	<u>Total Capital Cost (2004 \$)</u>	<u>Cost Effectiveness (2004 \$/ton)</u>
SCR (gas fuel)	5 – 25	748,000 – 2,018,000	1,606 – 3,203
SCR (oil fuel)	5 – 25	748,000 – 2,018,000	1,072 – 2,039

For additional information see: <http://www.epa.state.il.us/air/rules/rice/tsd-rice.pdf>

The cost effectiveness (in terms of \$/ton of NOx reduced) for application of SCR to any given combustion turbine is highly dependent upon the operating capacity factor of that engine.

4.5.5 Combustion Turbine NOx Control Summary

Industry information indicates that there are technically feasible, commercially available combustion and post combustion NOx controls available for combustion turbine. The most common combustion controls are water injection and the installation of low-NOx combustors. These controls are generally able to attain moderate levels of NOx reduction in retrofit application; approximately 40% for water injection and up to approximately 60% for low-NOx combustors. Due to the design differences between makes and models of combustion turbines, not all combustion turbines are able to achieve those levels of NOx reduction. Also because of the design differences between makes and models of combustion

turbines, water injection systems and/or low-NOx combustors must be designed for the specific make and model of combustion turbine. Water injection systems and/or low-NOx combustors are not available for all makes and models of existing combustion turbines. Some organizations market a NOx reduction system that incorporates both low-NOx combustors and water injection to optimize unit efficiency, operability, and emissions control over a wide range of unit load and ambient conditions.

Combustion turbine manufacturers offer multiple models of new combustion turbines with low NOx combustion technology that are capable of operating with NOx emission rates in the single digit ppmvd range.

Industry information also indicates that retrofit SCR is a technically feasible, commercially available post-combustion NOx control for combustion turbines. SCR is applicable and available for both retrofit and new unit installations. SCR is capable of achieving combustion turbine NOx reductions of 90% or more. Based on the available information, SCR appears to be the only commercially available combustion turbine NOx reduction technology capable of attaining those high levels of NOx reduction. While the SCR process is generally applicable to any combustion turbine, site specific conditions or economic considerations may affect the feasibility of a given SCR retrofit project. SCR systems are generally able to attain outlet NOx emission rates in the low single digit ppmvd range.

<u>NOx Control</u>	<u>Nameplate Rating (MW)</u>	<u>Estimated NOx Reduction (%)</u>	<u>Estimated Cost (\$)</u>
Water Injection	4 – 23	40	398,000 – 1,481,000
Low NOx Combustors	4 – 23	60	260,000 – 1,094,000
SCR	5 – 25	90	901,000 – 2,432,000

(Note: Estimated control costs are initial capital cost estimates only. Costs are based on “Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines”, adjusted for CPI.)

It should be noted that the range of costs for installation of the combustion related NOx reduction controls on combustion turbines is highly dependent upon the make and model of the combustion turbine, and less dependent upon the combustion turbine’s nameplate rating for this size range. Additionally, cost effectiveness (in terms of \$/ton of NOx reduced) of any NOx reduction project would be dependent upon the capacity factor of the affected combustion turbine.

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http://www.wrapair.org/forums/ssjf/documents/eictts/OilGas/WRAP_Phase_II_O&G_Update_II_Control053007.pdf

Attachment 1

Upstream Oil and Gas Sector NOx Emitting Equipment

OTR Region

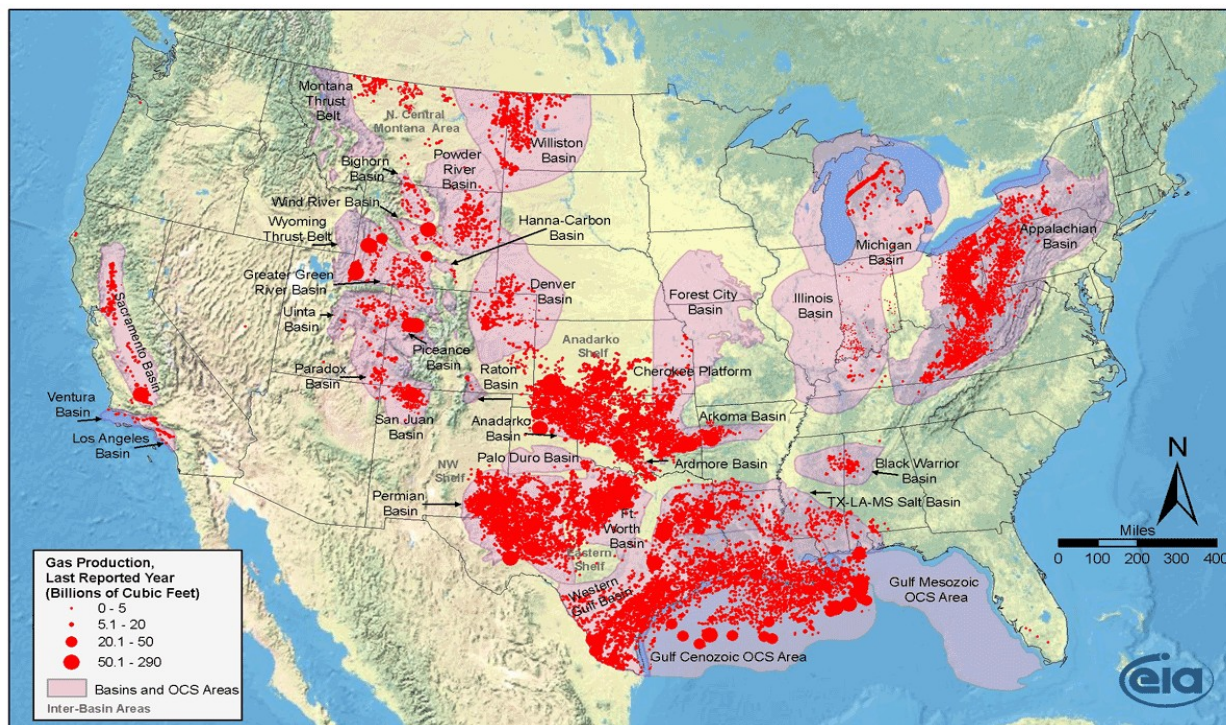
Oil and gas sector activities in the ozone transport region (OTR) that emit NOx closely mimic those of the overall lower 48 states, as discussed in the body of this document. Within the OTR these activities include crude oil and gas well drilling operations, oil well pumps and wellhead heaters, gas well compressors and wellhead gas heating, field gathering activities, mainline pumps and compressors, and underground storage activities.

OTR Oil and Gas Well Drilling

While both crude oil and natural gas are produced in the OTR, from an upstream activities standpoint the gas sector is larger and better documented than the oil sector.

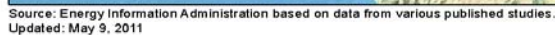
Gas drilling in the OTR includes drilling for conventional gas, shale gas, and coal bed methane. The following illustration from the EIA shows the conventional gas fields in the lower 48 states, including those in the OTR:

Gas Production in Conventional Fields, Lower 48 States

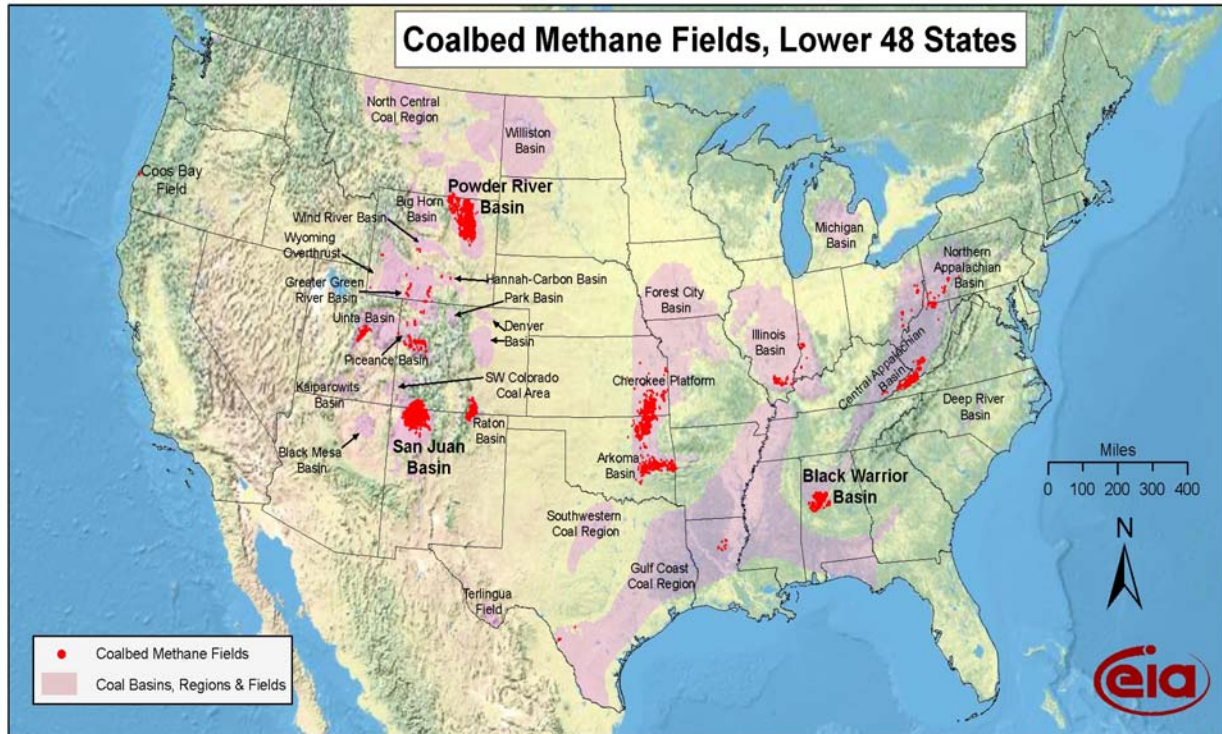


Source: Energy Information Administration based on data from HPDI, IN Geological Survey, USGS
Updated: April 8, 2009

The following illustration is also from the EIA website, and shows the coal bed methane fields in the lower 48 states, including those in the OTR:



The following illustration is also from the EIA website, and shows the coal bed methane fields in the lower 48 states, including those in the OTR:



Source: Energy Information Administration based on data from USGS and various published studies
Updated: April 8, 2009

Rotary drill rigs are utilized for the drilling of oil wells and gas wells. These drill rigs are moved from site to site to support the drilling of exploratory and production wells. Within the last decade, drill rigs have been employed to drill oil and/or gas wells in the OTR states of Maryland, New York, and Pennsylvania. The following table presents data from the EIA website, and shows the annual average number of rotary drill rigs in operation in these OTR states:

**Annual Average Count of Rotary Rigs in Operation
(Average of Monthly Averages)**

Year	Maryland	New York	Pennsylvania
2002	0	4	11
2003	0	3	10
2004	0	5	9
2005	0	4	13
2006	0	6	16
2007	1	6	16
2008	0	6	23
2009	0	2	42
2010	0	1	85
2011	0	0	110

Data from the RigData website indicates that as of the date the website was accessed, in the OTR only the states of New York and Pennsylvania have had rotary drill rigs in operation so far in 2012. The following table shows the number of drill rigs in operation by month for the OTR states:

Drilling Rigs In Operation 2012				
Weekly Average for the Month				
	January	February	March	April
New York	2	0	0	2
Pennsylvania	139	124	120	116

The RigData website also provided information concerning the number of wells started for each state by month. As of the date the website was accessed, the following table shows the number of wells started for the OTR states:

Well Starts 2012			
	January	February	March
New York	3	0	0
Pennsylvania	196	184	208

For the wells started in 2012, the RigData website provided data regarding the depth range of the wells and the approximate total number of feet drilled for those wells. As of the date the website the accessed, the following table shows the number of wells started for each depth range and the approximate total number of feet drilled for those wells:

Well Starts by Depth Range			
January – March 2012			
	1 – 2,499 ft depth	2,500 – 4,999 ft depth	5,000 – 9,999 ft depth
New York	1 well, 2000 ft	2 wells, 5,000 ft total	0
Pennsylvania	20 wells, 37,000 ft total	27 wells, 102,000 ft total	535 wells, 3,891,000 ft total

OTR Oil and Natural Gas Production

Within the OTR, New York and Pennsylvania are the two states that produce crude oil. Only a limited amount of data could be located documenting the number of oil wells in the New York and Pennsylvania. The following data is the latest data available from the EIA website, and represents the annual number of oil wells operating in the respective states:

	No. of Oil Wells	No. of Oil Wells
Year	New York	Pennsylvania
2000	NA	6011
2001	NA	6589
2002	916	5243
2003	2884	5480
2004	2968	5167
2005	2789	NA
2006	3121	NA
2007	2979	NA
2008	3271	NA
2009	3011	NA

Collectively, the production of crude oil in Pennsylvania and New York represent less than 0.5% of the crude oil produced in the US. The following table shows the annual crude oil production in Pennsylvania and New York for the last several years:

Year	New York Field Production of Crude Oil (Thousand Barrels)	Pennsylvania Field Production of Crude Oil (Thousand Barrels)
2001	166	1620
2002	165	2233
2003	144	2425
2004	170	2538
2005	197	3947
2006	319	3626
2007	380	3653
2008	386	3611
2009	339	3541
2010	378	3474
2011	390	3656

The above data was extracted from EIA sources, and includes the latest annual data available at the time the data was accessed. It can be seen in the above data that after a step increase in crude oil production around 2005, the crude oil production from New York and Pennsylvania was relatively flat through 2011.

Within the OTR, the states of Pennsylvania and New York are also two of the three natural gas producing states, the third state being Maryland. The following table shows the latest data available from the EIA website, and represents the annual number of gas wells in the respective states:

Year	Maryland Natural Gas Number of Gas and Gas Condensate Wells	New York Natural Gas Number of Gas and Gas Condensate Wells	Pennsylvania Natural Gas Number of Gas and Gas Condensate Wells
2001	7	5913	40100
2002	5	6496	40830
2003	7	5878	42437
2004	7	5781	44227
2005	7	5449	46654
2006	7	5985	49750
2007	7	6680	52700
2008	7	6675	55631
2009	7	6628	57356
2010	7	6736	44500

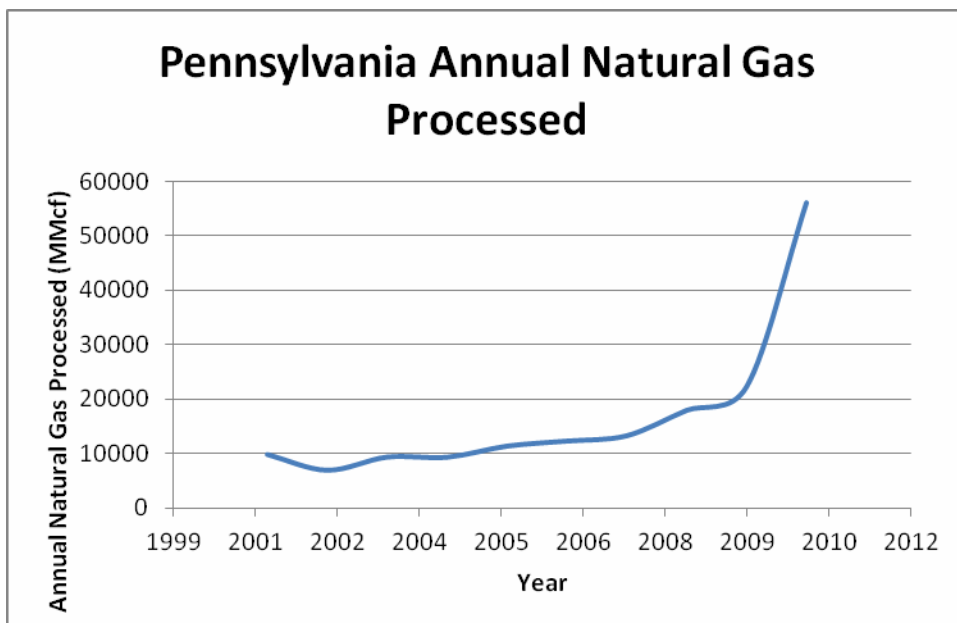
The following table shows the natural gas production in Maryland, New York, and Pennsylvania for the last several years:

Year	Maryland Natural Gas Gross Withdrawals (MMcf)	New York Natural Gas Gross Withdrawals (MMcf)	Pennsylvania Natural Gas Gross Withdrawals (MMcf)	Total OTR Natural Gas Gross Withdrawals (MMcf)
2001	32	27787	130853	158672
2002	22	36816	157800	194638
2003	48	36137	159827	196012
2004	34	46050	197217	243301
2005	46	55180	168501	223727
2006	48	55980	175950	231978
2007	35	54942	182277	237254
2008	28	50320	198295	248643
2009	43	44849	273869	318761
2010	43	35813	572902	608758

The above data was extracted from EIA sources, and includes the latest annual data available at the time the data was accessed. It can be seen in the above data that between 2001 and 2008 there was a slow, steady increase in the collective annual natural gas production from the three states. However, the data also indicates that beginning in 2009 that there was a sharp increase in natural gas production

collectively from the states. It can be seen that this increase is predominately from Pennsylvania, and that increase roughly corresponds to the expansion of shale gas development in Pennsylvania.

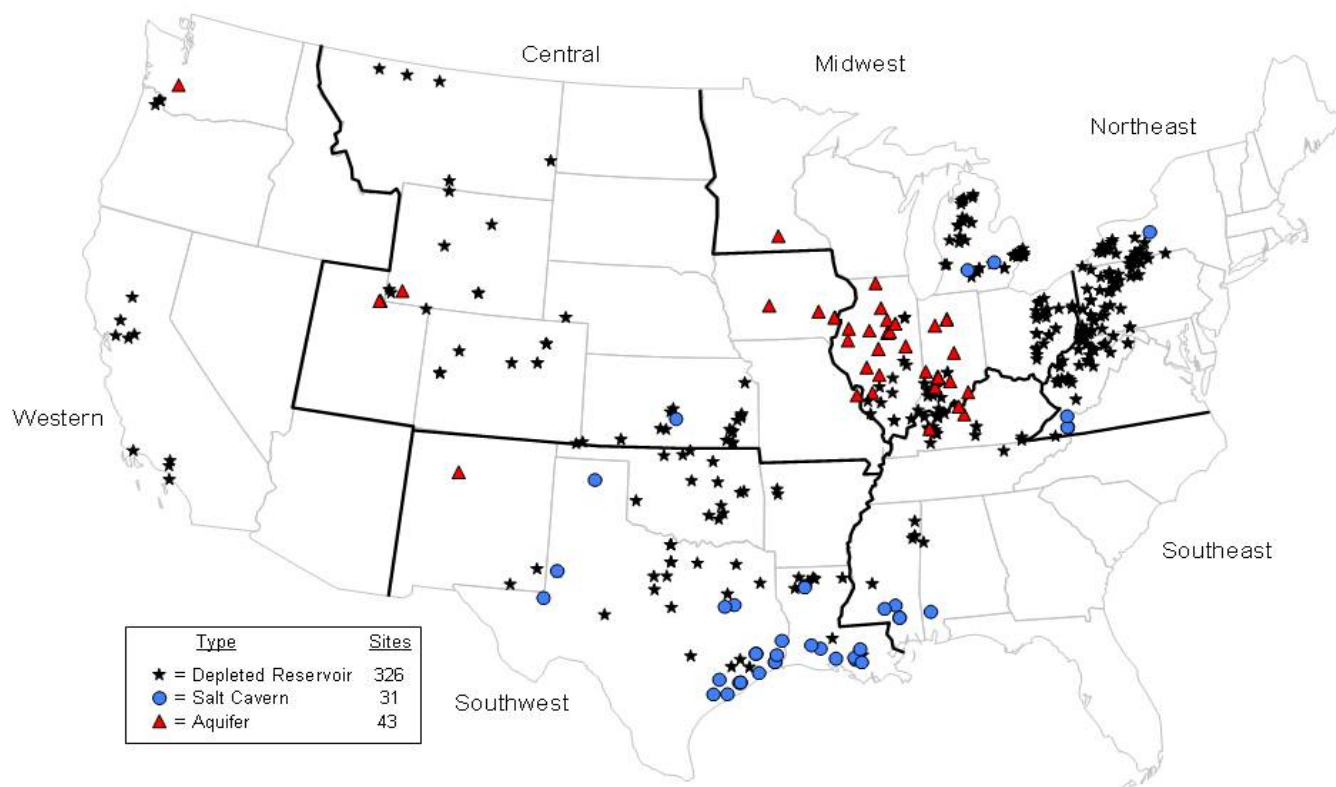
The sharp increase in natural gas production in recent years in Pennsylvania is also evidenced in the output from natural gas processing plants in Pennsylvania. (Pennsylvania is the only state in the OTR with large central natural gas processing plants according to EIA data.) Some natural gas requires processing before it is pipeline quality, and therefore must be appropriately processed before it can be injected into mainline or distribution pipelines. The following chart of EIA data shows the amount of natural gas processed in Pennsylvania's natural gas processing plants over the last several years:



OTR Underground Natural Gas Storage

The following map shows the natural gas storage facilities in the lower 48 states.

U.S. Underground Natural Gas Storage Facilities, 2007



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division Gas, Gas Transportation Information System, December 2008.

It can be seen in the map that within the OTR, New York and Pennsylvania are the primary locations of underground natural gas storage facilities. The natural gas storage facilities in the OTR are important for balancing natural gas demand with supplies during peak demand periods. In New York and Pennsylvania, the majority of the underground storage is depleted natural gas production fields, thereby potentially taking advantage of existing wells, gathering stems, pipeline connections, etc that were installed originally to facilitate natural gas extraction. New York also has a salt cavern natural gas storage facility. Pennsylvania has more underground natural gas storage facilities than any other state.

The compressors at underground storage facilities may be used to inject pipeline natural gas into storage and then re-inject the natural gas back into the pipelines for transportation to the users. EIA data from 2006 indicated that Pennsylvania and New York ranked 5th and 8th highest among states with the largest increase in natural gas underground storage deliverability for the period of 1998 through 2005. (Pennsylvania exhibited a 13% increase (969 MMcuft/day added) and New York exhibited a 44% increase (510 MMcuft/day added)).

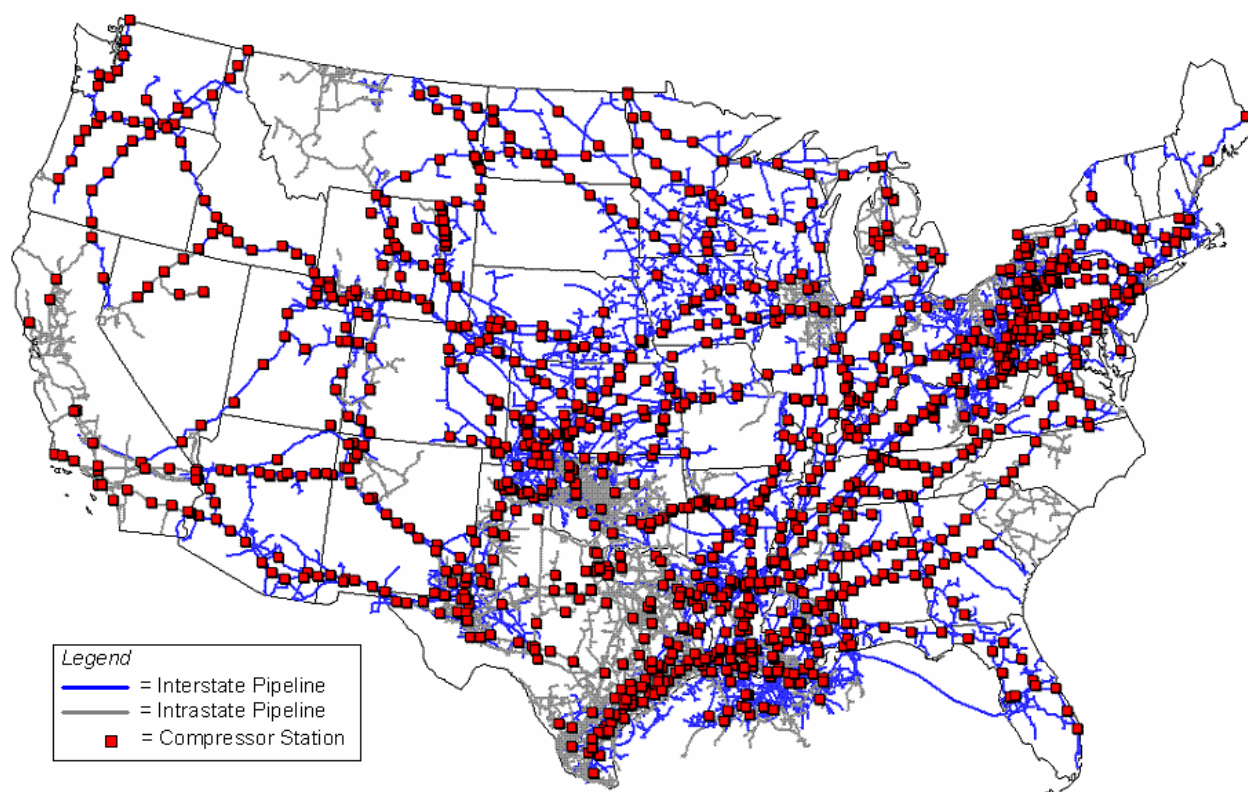
OTR State Natural Gas Underground Storage Capacity

State	Number of Storage Sites	Working Storage Capacity (bcf)
MD	1	17
NY	24	117
PA	50	406

OTR Natural Gas Pipeline Compressors

Mainline natural gas transmissions pipeline systems utilize compressors at gas compressor stations to maintain system flow and overcome pressure losses due to the movement of the natural gas through the natural gas pipeline system. These compressor stations are typically located at 40 mile to 100 mile intervals along the transmission pipeline, as required by the particular pipeline section duty, to maintain the required flow and pressure. These mainline natural gas compressor facilities will often include multiple gas compressors to add flexibility and reliability in meeting the variable natural gas flow demand. Below is a map from the EIA of the US interstate mainline gas system noting the location of the mainline compressor stations as of 2006. EIA and Federal Energy Regulatory Commission (FERC) data indicates that there have been a number of compressors stations (and compression additions to existing compressor stations) that have been put in service subsequent to 2006 to help meet the growing demand for natural gas as a fuel. Some of the new compression stations (and compression additions to existing compressor stations) have been added in the OTR.

U.S. Natural Gas Pipeline Compressor Stations, EIA, 2008



The map shows that there are many mainline compressor stations in the OTR, with a relatively high concentration in New York and Pennsylvania. Prime movers for these mainline compressors are typically natural gas fired reciprocating engines and combustion turbines, although there are also a number of electric motor gas compressor prime movers in the OTR. In some instances, combustion compressor prime movers and electric motor compressor prime movers are located in the same compressor facilities. The horsepower ratings of the individual combustion compressor prime movers range from less than 300 hp to 15,000 hp and more.

Many mainline natural gas compressor stations have multiple compressors operating in parallel to help meet large variations in the natural gas flow, and may also have some redundancy to minimize the impact of maintenance or problems with any given compressor unit. Industry data indicated that many of the mainline natural gas compressor stations have compressors in operation 24 hrs/day and 365 days/year, although not all compressors may be operating or may not be operating at high capacity. Within the OTR, FERC compressor facility specific (not unit specific) data indicated that for 2007 the range of facility operating capacity (in terms of compressor operating hours) ranged from 0% to approximately 95%, with an average of approximately 35%. For many mainline natural gas compressor facilities, reciprocating engines are preferred for their ability to adjust their output to meet the pipeline demand. Compressor loading will tend to increase during periods of high natural gas demand, such as cold periods with high heating fuel demand or high electric demand days in the northeast when natural gas fired electric generation is a significant consumer of natural gas. Within the OTR, FERC compressor facility specific data for 2007 indicated that 24 of 141 compressor facilities saw their peak 2007 day during the ozone season.

A review of 2010 FERC Form 2 and Form 2A data indicated that in 2010 there were 149 compressor stations in the OTR used for natural gas transmission service. The FERC data indicated that these compressor stations collectively had 518 natural gas compressors with a collective total horsepower rating of 2,053,510 hp (an unknown portion of which is likely powered by electric motors). The FERC data indicates that in 2010 these facilities collectively combusted 47,426,022 dth (approximately 47,426,022,000 cf) of natural gas for compression services.

Data from MARAMA's 2007 Point Source Inventory was reviewed to obtain a better understanding of the makeup of the OTR's population of fuel-combustion natural gas compressor prime movers. The review of the data indicated that a number of the units in the database did not give sufficient information to categorize each unit, sometimes not identifying the prime mover configuration (engine, turbine, 2SLB, etc), manufacturer, model number, output capacity, etc. It was possible to supplement some of the MARAMA data with information obtained from internet searches of compressor station operating permits, but there remains a significant number of units in the database with only partial information. Also, it is likely that the 2007 MARAMA data includes compressor units utilized for field gathering and underground storage in addition to the mainline compressors.

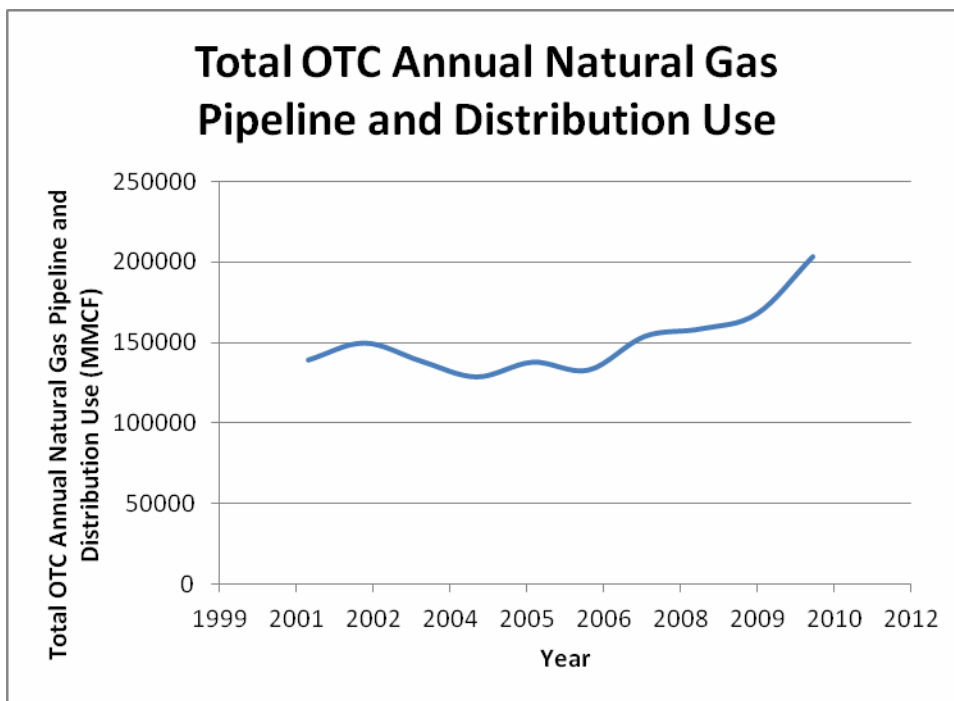
From the available information, it appears that the population of OTR natural gas compressor prime movers is diverse with regards to make, model, and capacity. For the reciprocating engines (2SLB, 4SLB, and 4SRB), the available data indicates that there are at least 60 different engine models spread among 13 different manufacturers. For the turbines, the available data indicates that there are at least 20 different models spread among 6 different manufacturers. [It should be noted that the number of manufacturers represented in the data are sometimes the result of mergers and buyouts. For example, the reciprocating engine manufacturer Superior (existing since the early 1900's) became White-Superior in the mid-1960s, then became Cooper-Superior in the early 1970s, and became Superior (within Cameron) in the mid-1970s. In fact, Cameron is also the current OEM for the Cooper-Bessemer line of engines.]

Within the available OTR compressor inventory data for reciprocating engines, the range of output for 2SLB reciprocating engines is approximately 400 HP to 5500 HP, the range of output rating for 4SLB reciprocating engines is approximately 650 HP to 4,300 HP, and the range of output rating for 4SRB reciprocating engines is approximately 200 HP to approximately 1,300 HP. Also within the available OTR compressor inventory data for combustion turbines, the range of output is approximately 1,000 HP to approximately 20,000 HP.

The data inventory also does not provide an indication of the vintage or age of the prime movers. Of most concern is the vintage of the reciprocating engines, as they have been available as compressor prime movers longer than combustion turbines and have been shown to have long service life. Industry information indicates that nationally there are many natural gas compression reciprocating engines that are in excess of 40 years old. While the data available at this time for the OTR natural gas pipeline compression reciprocating engines does not include an indication of the age of these engines, some inference can be made that many "vintage" reciprocating engine compressor prime movers continue in operation in the OTR by reviewing the manufacturer and model number of the subject engines. For example, industry information indicates that the Cooper-Bessemer family of GMW 2-stroke integral engines was manufactured between 1946 and 1965. The 2007 MARAMA database indicates that there are a number of such engines in the OTR that were still operating in 2007. The database does not contain sufficiently detailed information to determine if any of these vintage engines have undergone NOx RACT or been subject to any other NOx reduction activities.

The 2007 MARAMA point source data indicated that, collectively, the compressor prime movers in the OTR compressor facilities emitted approximately 11,000 tons of NOx in 2007, with the average facility emitting approximately 112 tons of NOx in 2007. The highest NOx emitting facility emitted in excess of 1100 tons of NOx in 2007, those emissions collectively from 12 reciprocating engines. Because portions of the 2007 MARAMA point source data is presented as "per facility" rather than all on a "per unit" basis, it is difficult to get a thorough understanding of the unit-by-unit annual NOx emissions of the OTR gas compressor prime movers. It appears that the range of unit specific 2007 annual NOx emissions ranged from approximately 177 tons of NOx to less than 0.1 ton of NOx. The gas compressor prime movers at the upper end of the range appear to be predominately gas turbines and 2-stroke lean burn reciprocating engines.

The following graph reflects EIA data and shows the annual amount of natural gas consumed in the OTR for use in natural gas pipeline and distribution operations. This natural gas consumption is primarily for compression. The graph shows that there has been a significant increase in the amount of natural gas utilized for gas pipeline and distribution purposes over the last few years. This increase in use follows the increased demand for natural gas from OTR users, and the increased production of natural gas from OTR sources.

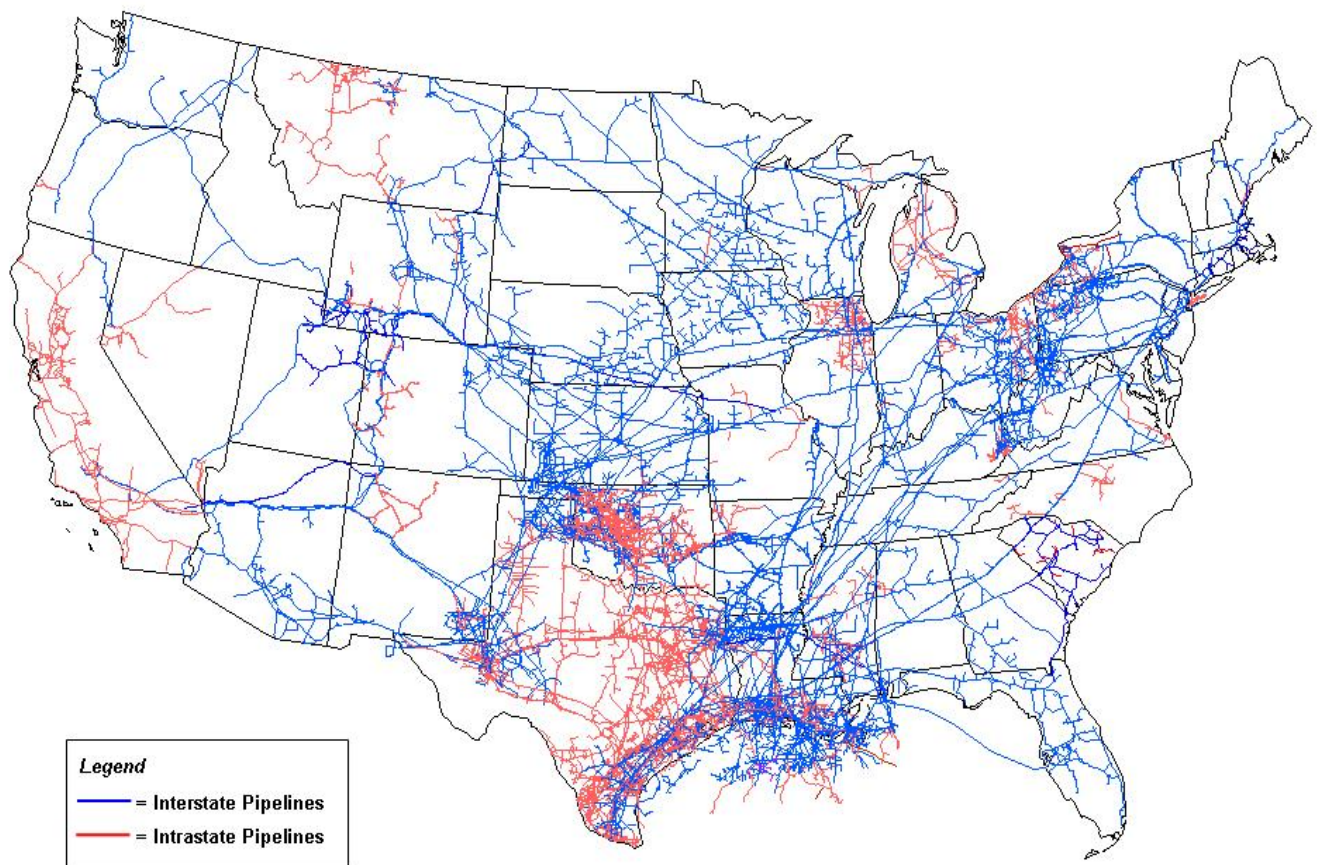


OTR Mainline Natural Gas Pipelines

While natural gas pipelines do not emit NO_x themselves, the existence of the complex pipeline system is critical to the function of the natural gas industry in the OTR, and therefore the NO_x emitting processes associated with the natural gas industry in the OTR. Interstate pipelines deliver natural gas to the OTR through several intrastate natural gas pipelines and to many local distribution companies in the OTR. In addition, the interstate pipelines also serve many large industrial concerns and natural gas fired electric power generation facilities.

The natural gas pipeline and local distribution companies serving the OTR have access to supplies from several major domestic natural gas producing areas, including those in the OTR, and from Canada. Natural gas from outside the OTR flows into the region from the Southeast through Virginia and West Virginia, and from the Midwest through West Virginia and Pennsylvania. Canadian natural gas imports come into the OTR principally through New York, Maine, and New Hampshire.

Liquefied natural gas (LNG) supplies also enter the region through import terminals located in Massachusetts, Maryland, and New Brunswick, Canada.



Source: Energy Information Administration, Office of Oil & Gas, Natural Gas Division, Gas Transportation Information System

The interstate natural gas pipeline systems that serve the OTR include the following:

- One of the largest natural gas pipelines transporting natural gas into the OTR is the Transcontinental Gas Pipeline Company system, which extends from South Texas to the New York City area.
- The Tennessee Gas Pipeline Company and the Texas Eastern Transmission Company natural gas pipeline systems bring supplies to the OTR from Texas, Louisiana, and the Gulf of Mexico. The Tennessee Gas Pipeline Company system, unlike the Transcontinental Gas Pipeline Company and Texas Eastern Transmission Company systems, extends its service northward as far as New Hampshire and is a major transporter of natural gas to Connecticut, Massachusetts, and Rhode Island.

- The Tennessee Gas Pipeline Company system is also a significant source of supply for the regional Algonquin Gas Transmission Company system, which is the principal interstate natural gas pipeline serving the Boston, Massachusetts area. The Texas Eastern Transmission Company, an affiliate of the Algonquin Gas Transmission Company, is the primary source of supply for that pipeline, delivering approximately 65 percent of Algonquin's requirements at interconnections in New Jersey. The Algonquin Gas Transmission Company system has the capability to move a significant portion of its system capacity from New Jersey into the New York metropolitan area.
- The Algonquin Gas Transmission Company is also receives natural gas processed at the Northeast Gateway liquefied natural gas (LNG) import terminal located 10 miles offshore of Massachusetts. The Northeast Gateway port's infrastructure features two submerged turret loading buoys for off loading, and is linked to the Algonquin Gas Transmission Company system by a 16-mile submerged pipeline.
- The Columbia Gas Transmission Company has an extensive network of natural gas pipelines that provide service to Maryland, New Jersey, New York, and Pennsylvania. The Columbia pipeline transports natural gas from the Gulf of Mexico as well as natural gas produced in the Appalachian region. The Columbia Gas Transmission Company supplies some of the largest natural gas distribution companies in the OTR.
- The Millennium Pipeline natural gas system begins at an interconnection with the Empire Pipeline system in southwest central New York State and terminates in the New York City metropolitan area. It is part of an overall regional effort involving expansion of the existing Empire, Algonquin and Iroquois Pipelines, which are among its major supply sources.
- The Dominion Transmission Company system serves Maryland, New York, and Pennsylvania. The Dominion Transmission Company also serves some of the largest natural gas distribution companies in the OTR.

In addition to the interstate natural gas pipeline companies that bring natural gas into the OTR, several smaller interstate natural gas pipeline companies operate primarily within the OTR (and OTR-neighboring states). Among these systems are:

- Equitrans Inc. serves western Pennsylvania, and its pipeline system was developed to move local production to regional markets through connections with local natural gas field gathering, distribution, and storage interconnections.
- The Eastern Shore Natural Gas Company is the only natural gas pipeline serving southern Delaware and the lower Delmarva Peninsula. It receives its supplies from Transcontinental Gas Pipeline Company and Columbia Gas Transmission Company at points in southeastern Pennsylvania, with a route that takes it southward through Delaware to Maryland's eastern shore.
- The Granite State Transmission Company receives natural gas from the Tennessee Gas Pipeline Company and/or the PNGTS/Maritimes and Northeast Pipeline system at the southern New

Hampshire/Massachusetts border. From there it transports to customers in New Hampshire and to the Northern Utilities Company system.

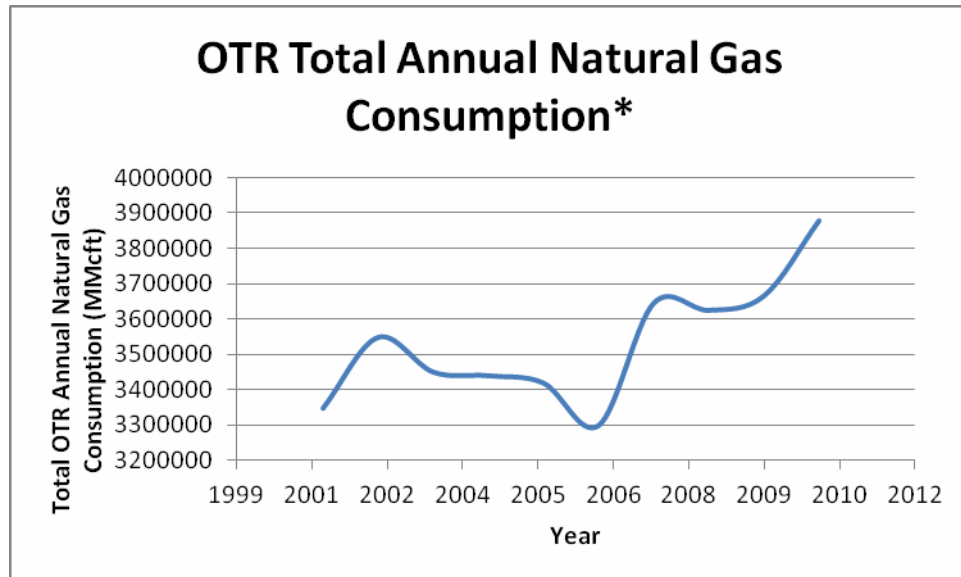
- The KeySpan Energy Delivery Company is the principal provider of natural gas service to New York City and Long Island, New York, its intrastate operations also include service in Massachusetts and New Hampshire as well.

Canada is also a significant source of natural gas to the OTR through the pipeline system. Some of the more significant sources include the following:

- The Iroquois Gas Transmission Company system is supplied with natural gas from the TransCanada Pipeline Ltd system in Ontario, Canada.
- The Empire Pipeline Company system, an intrastate affiliate of National Fuel Gas Supply Corporation, brings in Canadian natural gas at Grand Island, New York to north central New York State with interconnections to the Dominion Transmission Company and National Fuel Gas Supply Corporation systems. These latter two companies also access Canadian natural gas supplies from the Tennessee Gas Pipeline, which imports Canadian natural gas through Niagara Falls, New York.
- The Portland Natural Gas Transmission System (PNGTS) merges with the Maritimes and Northwest Pipeline system at Wells, Maine, where they form a joint natural gas pipeline that extends south through southern New Hampshire and terminates in northern Massachusetts (with an interconnection to the Tennessee Gas Pipeline Company system). PNGTS also provides bidirectional service to its customers allowing shippers of Canadian Sable Island natural gas (which use the Maritimes & Northeast Pipeline Company system) the opportunity to redirect some of their natural gas to markets located in Quebec (which previously had access only to western Canadian natural gas supplies).
- The U.S. portion of the Maritimes and Northeast Pipeline Company system begins at Calais, Maine, at the Canadian border and extends to Wells, Maine. The Maritimes and Northeast Pipeline system was built to access natural gas production off the eastern coast of Canada (Sable Island) and to transport it to New England. The Maritimes and Northeast Pipeline Company system was extended from Boston, Massachusetts to provide natural gas that area. The system also can transport natural gas processed at the Canaport liquefied natural gas (LNG) import terminal located in New Brunswick, Canada, to New England markets.
- Several smaller regional natural gas importing pipelines, such as North County Pipeline Company and the St. Lawrence Gas Company, both located in upper New York State, and the Vermont Gas Systems Company, the only natural gas pipeline in the State of Vermont, depend upon Canadian natural gas imports completely for their natural gas supplies since they do not interconnect with any other U.S. natural gas pipeline.

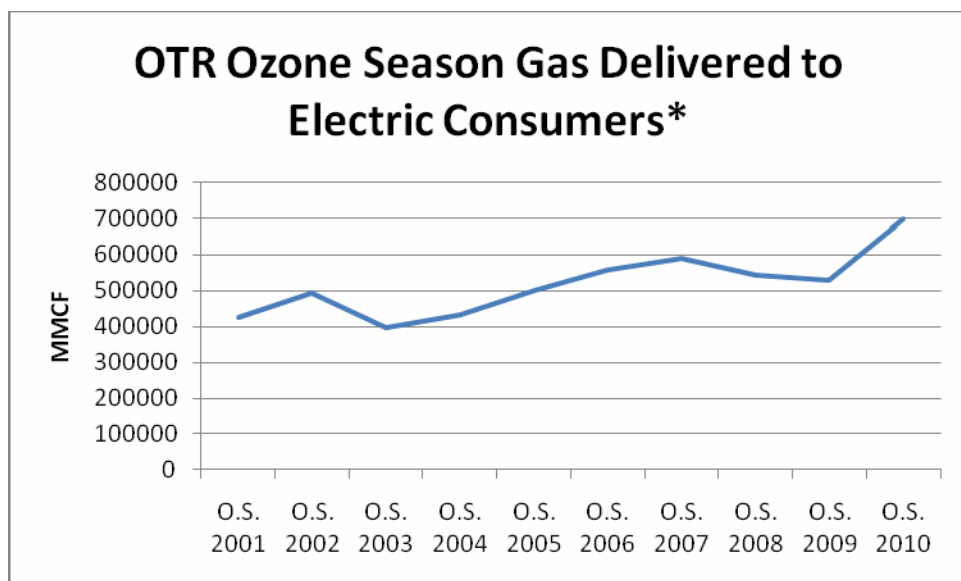
The robust natural gas pipeline system supplying and distributing natural gas in the OTR has been instrumental in supporting the widespread use of natural gas for residential, commercial, and industrial

purposes. As shown in the following graph, the use of natural gas has been on a general incline in the OTR as a whole over the last decade:

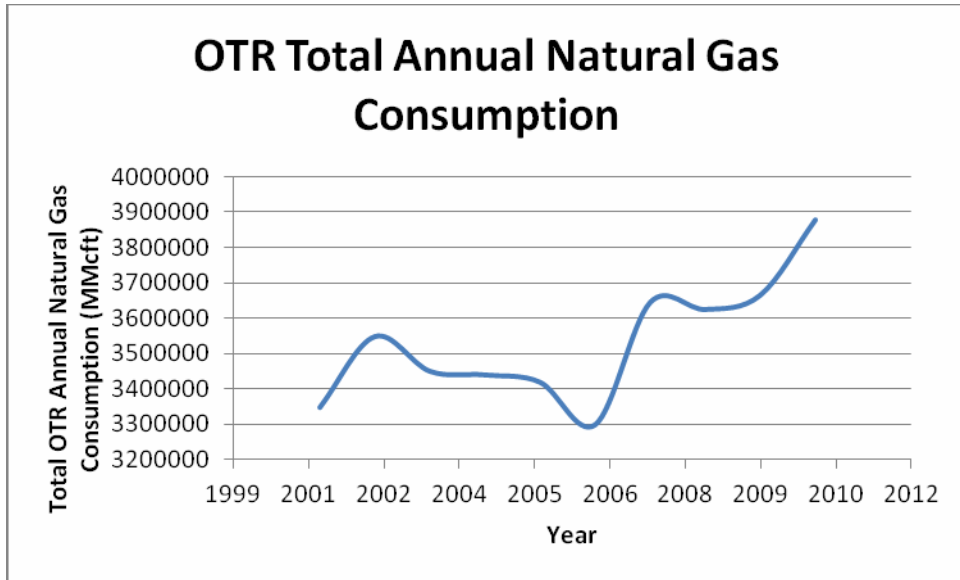


*Excluding Virginia

Some of the growth in the OTR's natural gas consumption has been due to increased use by electric generating units in the OTR. This increase is evident in both the OTR annual total electric generating unit natural gas consumption and the OTR ozone season total electric generating unit natural gas consumption, as shown in the following two graphs:



*Excluding VA

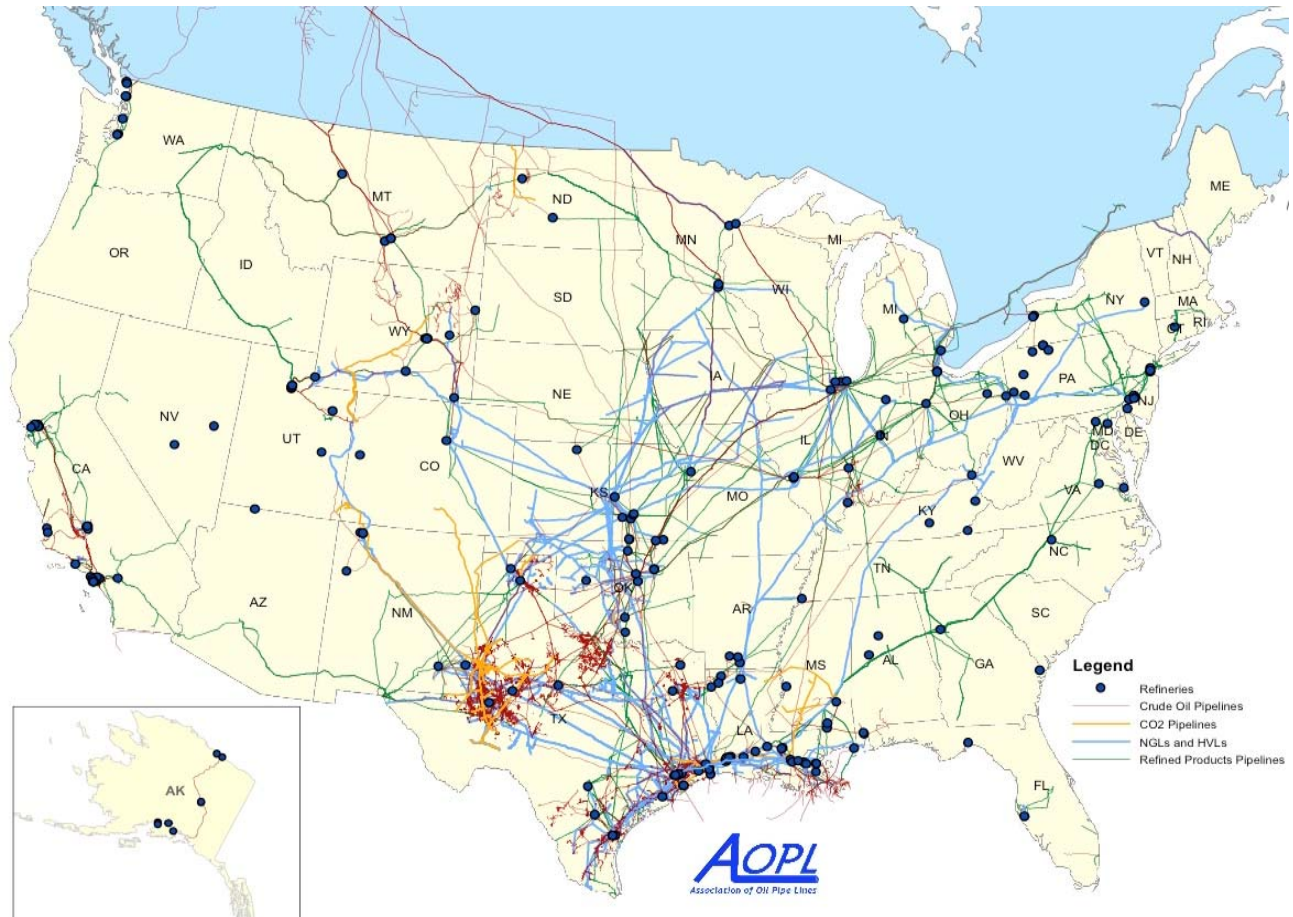


Note: Excluding VA

Crude Oil and Refined Products Pipelines

Within the OTR there are also a number of pipelines for transporting crude oil and refined products. Little information could be located regarding the number and makeup of pumping stations on those pipelines. The following map shows the relate pipeline system for the lower 48 states. It can be seen in the map that, relative to natural gas pipeline network system, the crude oil and refined products pipeline network is far less extensive in the OTR states.

Lower 48 States Crude Oil and Refined Products Pipelines, 2009



Source: Petroleum Geographics Corporation 2012

Attachment 2

2010 FERC Form 2 and Form 2A Data

OTR Natural Gas Compressors

State	Service	Facility Name/Location	No. Compressors	Total HP	Gas Compressor 2010 Fuel Use (MMBTU/yr)	Compressor 2010 Operating Hrs	Electric Compressor 2010 Power Usage (kwhr)
CT	Transmission	Chaplin Compressor Station, Chaplin, CT	2	13900	287115	4417	0
CT	Transmission	Cromwell Compressor Station, Cromwell, CT	8	21400	647985	27190	0
CT	Transmission	Oxford Compressor Station, Oxford, CT	3	37700	285982	3258	0
CT	Transmission	Brookfield Compressor Station, Brookfield, CT	2	18010	754008	11737	829750
CT	Transmission	Milford Compressor Station, Milford, CT	2	20620	260736	3101	509640
MA	Transmission	#261 - Agawam, MA Electric/Gas	5	17110	112038	6598	3199914
MA	Transmission	#264 - Charlton City, MA	2	12552	740495	7674	0
MA	Transmission	#266A - Mendon, MA	3	9170	167252	6769	0
MA	Transmission	#267 - Hopkinton, MA	5	5000	48126	728	0
MD	Transmission	Rutledge, MD	3	12000	0	7984	17053583
MD	Undrgrd Strg	Accident, MD	2	11000	86106	5212	1167552
MD	Transmission	No. 190 Ellicott City, Maryland	12	29250	1980798	96310	0
ME	Transmission	Baileyville Compressor Station, ME	2	16622	258129	3550	0
ME	Transmission	Richmond Compressor Station, ME	2	16622	208448	3108	0
ME	Transmission	Wood Chopping Ridge Compressor Station, ME	1	18085	367363	3323	0
ME	Transmission	Brewer Compressor Station, ME	1	18085	233651	2494	0
ME	Transmission	Searsmont Compressor Staion, ME	1	18085	123360	553	0
ME	Transmission	Westbrook Compressor Station, ME	2	26666	129882	1418	0
ME	Transmission	Eliot Compressor Station, ME	1	8960	20775	256	0
NH	Transmission	#270B1 - Pelham	1	6053	7959	97	0
NJ	Transmission	Hanover Compressor Station, Hanover, NJ	3	22000	193007	6245	0
NJ	Transmission	#325 - Sussex, NJ	2	14991	276720	5675	0
NJ	Transmission	Franklin (Freehold), NJ	1	5000	0	12	356417
NJ	Transmission	Hanover, NJ	1	6500	168087	6	180960
NJ	Transmission	Lambertville, NJ	7	24600	509431	22921	6818612
NJ	Transmission	Linden, NJ	3	6150	228305	13840	363520
NJ	Transmission	No. 205 Lawrenceville, New Jersey	3	30200	0	3333	31162606
NJ	Transmission	No: 207 Sayreville, New Jersey	2	10000	1806	4519	16011555
NJ	Transmission	No. 505 Centerville, New Jersey	8	16000	132840	8776	0
NJ	Other	No. 240 Hackensack Meadows, New Jersey	5	4320	148182	11445	0
NY	Transmission	Southeast Compressor Station, Southeast, NY	5	40010	1299694	14952	0
NY	Transmission	Stony Point Compressor Station, Stony Point, NY	7	38800	870835	13768	0
NY	Transmission	Corning, NY	1	1000	5904	2551	0
NY	Undrgrd Strg	Dundee, NY	3	1880	618	2133	0
NY	Undrgrd Strg	North Greenwood, NY	1	1000	0	0	0
NY	Undrgrd Strg	Quinlan, NY	2	4740	57565	2085	0
NY	Undrgrd Strg	Woodhull, NY	8	14700	260074	14522	0
NY	Transmission	Borger, NY	3	21910	236330	4100	0
NY	Transmission	Brookmans Corner, NY	1	7300	11139	114	0
NY	Transmission	Lockport, NY	0	0	0	0	0
NY	Transmission	Utica, NY	7	9500	34762	3813	0

NY	Transmission	Oakfield NY	2	20620	20134	220	262560
NY	Transmission	Croghan Compressor Station, Croghan, NY	2	17180	333832	4548	702880
NY	Transmission	Wright Compressor Station, Wright, NY	2	14302	436558	7607	513456
NY	Transmission	Athens Compressor Station, Athens, NY	1	10028	228932	2667	442080
NY	Transmission	Boonville Compressor Station, Boonville, NY	1	18371	206107	1533	620320
NY	Transmission	Dover Compressor Station, Dover, NY	1	18371	330391	2510	948538
NY	Transmission	Corning Millenium, NY	1	15000	0	1611	0
NY	Field	Field Compressor St - Appalachian Field	1	450	8262	8112	186221
NY	Undrgrd Strg	Beech Hill	3	8350	12113	8068	388560
NY	Undrgrd Strg	Derby	1	75	400	1832	9183
NY	Undrgrd Strg	Independence	4	5000	104882	10801	324800
NY	Undrgrd Strg	Limestone	1	800	31525	4328	97680
NY	Undrgrd Strg	Nashville	3	3320	20434	4543	292000
NY	Undrgrd Strg	Porterville	4	600	30413	5721	116682
NY	Undrgrd Strg	Tuscarora	2	1440	40840	4876	101496
NY	Undrgrd Strg	Zoar	8	1200	39286	18824	150880
NY	Transmission	#224 - Clymer, NY	4	8000	309015	18570	0
NY	Transmission	#229 - Hamburg, NY	6	8400	529074	46324	0
NY	Transmission	#230C - Lockport, NY	4	18000	8213	327	0
NY	Transmission	#233 - Geneseo, NY	2	7000	148178	3463	0
NY	Transmission	#237 - Clifton Springs, NY	3	8000	346521	13720	0
NY	Transmission	#241 - Lafayette, NY	5	18400	591170	20342	0
NY	Transmission	#245 - West Winfield, NY	12	19700	698051	44411	0
NY	Transmission	#249 - Carlisle, NY	4	16200	616398	18652	0
NY	Transmission	#254 - Nassau, NY	7	18710	410132	9804	0
NY	Transmission	#405A - CONNEXION NEW ENGLAND	1	7700	244347	4404	0
PA	Transmission	Artemas #2, PA	3	3670	0	1270	0
PA	Transmission	Delmont, PA	2	1954	56852	9200	0
PA	Transmission	Downingtown, PA	2	12000	0	7096	25681552
PA	Transmission	Eagle, PA	4	8050	255513	18536	0
PA	Transmission	Easton, PA	3	2890	11615	1225	0
PA	Transmission	Ellwood City, PA	2	1000	10570	1886	0
PA	Transmission	Gettysburg, PA	4	7500	233265	7969	0
PA	Transmission	Greencastle, PA	4	7070	265821	9314	0
PA	Transmission	Hellertown, PA	2	2200	21718	2502	0
PA	Transmission	Marietta, PA	3	4050	0	6281	0
PA	Transmission	McClellandtown, PA	1	225	0	0	0
PA	Transmission	Milford, PA	2	680	0	9	0
PA	Transmission	Renovo, PA	5	3370	30348	16619	0
PA	Transmission	Rimersburg, PA	1	320	13299	4692	0
PA	Transmission	Salisbury, PA	5	5480	458179	31623	0
PA	Transmission	Waynesburg, PA	5	5400	470930	22856	0
PA	Undrgrd Strg	Artemas #1, PA	2	4000	177424	8242	0
PA	Undrgrd Strg	Donegal, PA	2	2000	41653	4975	0
PA	Undrgrd Strg	Holbrook, PA	1	130	0	0	0
PA	Extraction	Hutchinson, PA	2	250	0	3564	130880
PA	Undrgrd Strg	Boom, PA	2	5200	3745	26	0
PA	Undrgrd Strg	Ellisburg, PA	8	18400	298419	24948	0
PA	Undrgrd Strg	Greenlick, PA	4	13600	394904	12019	0
PA	Undrgrd Strg	Harrison, PA	6	11100	84666	11300	0

PA	Undrgrd Strg	Leidy, PA	13	25800	427133	38719	0
PA	Undrgrd Strg	Lincoln Heights, PA	2	510	6367	9330	0
PA	Undrgrd Strg	North Oakford, PA	0	0	0	0	22730086
PA	Undrgrd Strg	North Summit. PA	2	6400	114736	4468	0
PA	Undrgrd Strg	Oakford, PA	15	43800	309724	44620	0
PA	Undrgrd Strg	Sabinsville, PA	8	12870	218612	13035	0
PA	Undrgrd Strg	South Oakford, PA	4	24200	122824	20655	28479000
PA	Undrgrd Strg	State Line, PA	4	4650	63271	5396	0
PA	Undrgrd Strg	Tioga, PA	2	8400	55413	3679	0
PA	Transmission	Ardell, PA	1	15000	304790	1822	0
PA	Transmission	Ardell 2 PA	2	3550	0	8767	0
PA	Transmission	Beaver, PA	4	12800	539427	23243	0
PA	Transmission	Bedford-TE, PA	0	0	0	0	10541707
PA	Transmission	Big Run, PA	1	1775	81786	8637	0
PA	Transmission	Centre,PA	2	12400	17980	298	0
PA	Transmission	Chambersburg, PA	4	24800	91016	5402	15584000
PA	Transmission	Chambersburg-TE, PA	0	0	0	0	5303820
PA	Transmission	Cherry Tree, PA	2	1520	84100	16146	0
PA	Transmission	Connellsville-TE, PA	0	0	0	0	0
PA	Transmission	Crayne, PA	2	15600	604644	10636	0
PA	Transmission	Finnefrock, PA	6	17500	721073	30509	0
PA	Transmission	Helvetia, PA	1	330	14608	5966	0
PA	Transmission	J.B. Tonkin, PA	1	6000	313000	7796	0
PA	Transmission	Little Greenlick, PA	3	11135	202960	8515	0
PA	Transmission	Luthersburg, PA	2	880	34281	8730	0
PA	Transmission	NFG-Ellisburg, PA	0	0	0	0	0
PA	Transmission	Perulak, PA	1	4735	99400	3674	0
PA	Transmission	Punxsutawney, PA	3	13132	397058	13087	0
PA	Transmission	Rochester Mills, PA	3	1320	69928	19079	0
PA	Transmission	Rock Springs, PA	2	4740	127	102	0
PA	Transmission	Rural Valley, PA	2	5325	104902	6433	0
PA	Transmission	Sabinsville, PA	1	5800	0	17	0
PA	Transmission	South Bend, PA	6	12000	262572	14602	0
PA	Transmission	Stoney Run, PA	3	1152	31542	9646	0
PA	Transmission	Uniontown-TE, PA	0	0	0	0	18220824
PA	Undrgrd Strg	Hartson-Washington County, PA	3	3300	114572	12354	0
PA	Transmission	Pratt-Greene County, PA	5	4800	179718	23494	0
PA	Field	Mt. Morris-Greene County, PA	2	220	4007	8826	0
PA	Field	Ryerson-Greene County, PA	1	41	0	0	0
PA	Field	Waynesburg-Greene County, PA	2	3600	203445	15651	0
PA	Undrgrd Strg	Boone Mountain	2	300	10583	318	36313
PA	Undrgrd Strg	Carter Hill	2	765	2270	678	45687
PA	Undrgrd Strg	Ellisburg	4	9445	0	19892	0
PA	Undrgrd Strg	Henderson	2	2700	125012	9575	193240
PA	Undrgrd Strg	Queen	4	450	14507	12611	51636
PA	Undrgrd Strg	Summit	2	880	14606	2324	123250
PA	Undrgrd Strg	Wellendorf	1	325	259	528	0
PA	Transmission	East Fork	5	3060	40543	9332	82669
PA	Transmission	Eldred	2	300	14770	10710	60186
PA	Transmission	Heath	1	1160	1489	7107	385200

PA	Transmission	Island Run	4	615	17527	11507	130386
PA	Transmission	Kaylor	1	145	10879	8091	13776
PA	Transmission	Knox	4	1968	64031	20087	124617
PA	Transmission	Lamont	8	1490	51257	30288	263200
PA	Transmission	Roystone	12	5500	189451	62384	149443
PA	Transmission	Sackett	4	675	28152	25532	125954
PA	Transmission	Van	2	476	5750	9346	7766
PA	Transmission	Concord	5	11250	23546	1276	332000
PA	Transmission	Costello	2	1440	0	14985	28074
PA	Transmission	Ellisburg	5	11450	491390	11450	812700
PA	Transmission	Lockport	4	18000	41925	0	0
PA	Transmission	Boone Mountain	1	280	0	5269	0
PA	Transmission	Nashville	1	225	0	3471	0
PA	Transmission	Reynoldsville	1	150	7720	6891	40903
PA	Transmission	Bowen	1	1340	360	65	23825
PA	Undrgrd Strg	#313 - Coudersport, PA	14	24270	1051775	69136	0
PA	Transmission	#219 - Mercer, PA	14	21550	867950	63824	0
PA	Transmission	#307 - Pigeon, PA (Kane)	6	15500	661587	29745	0
PA	Transmission	#313A Ellisburg, PA	2	4730	131993	8594	0
PA	Transmission	#315 - Wellsboro, PA	1	9300	70305	589	0
PA	Transmission	#317 - Troy, PA Electric	1	13000	4355	1588	7303548
PA	Transmission	#319 - Wyalusing, PA	2	9000	165676	3426	0
PA	Transmission	#321 - West Clifford, PA	3	14100	275679	7815	0
PA	Transmission	#323A - Hawley, PA (Stagecoach) Electric	1	13400	740	3918	32003200
PA	Transmission	Armagh, PA	1	22000	429957	1631	150900
PA	Transmission	Bechtelsville, PA	4	33500	1353738	20510	744902
PA	Transmission	Bedford, PA	11	33880	307777	29591	47453065
PA	Transmission	Bernville, PA	2	41800	953347	4919	591360
PA	Transmission	Heidlersburg, PA	1	16000	0	2325	14020634
PA	Transmission	Chambersburg, PA	2	41300	0	3595	16217920
PA	Transmission	Delmont, PA	12	46400	1901482	55591	2034669
PA	Transmission	Entriiken, PA	1	22000	344877	1476	333840
PA	Transmission	Grantville, PA	4	33500	1571988	20018	875712
PA	Transmission	Holbrook, PA	15	58800	1908009	49712	2164622
PA	Transmission	Leidy, PA	4	8100	0	12443	189160
PA	Transmission	Lilly, PA	4	34800	1601960	22505	679680
PA	Transmission	Marietta, PA	7	23960	756327	17906	757200
PA	Transmission	Perulack, PA	4	34800	1594479	25627	1628800
PA	Transmission	Phoenixville,PA/Eagle, Pa	1	4000	0	1497	1605646
PA	Transmission	Shermans Dale, PA	2	41800	1062290	5403	531520
PA	Transmission	Uniontown, PA/Connelsville	8	79200	1293221	16995	72090151
PA	Transmission	Waynesburg, PA	1	5000	169717	4395	111200
PA	Undrgrd Strg	Leidy, PA	13	25800	242377	38719	0
PA	Undrgrd Strg	Oakford, PA (Oakford)	15	43800	358108	44620	0
PA	Undrgrd Strg	Oakford, PA (South Oakford)	4	24200	137830	20655	0
PA	Undrgrd Strg	Oakford, PA (Lincoln Heights)	2	510	9203	9330	0
PA	Undrgrd Strg	No. 530 Leidy-Tamarack Storage Field, PA	0	0	2243866	0	0
PA	Undrgrd Strg	No. 535 Wharton Storage Field, PA	5	8500	121644	20106	0
PA	Transmission	No. 195 Delta, Pennsylvania	5	19460	906501	35626	0
PA	Transmission	No. 200 Malvern, Pennsylvania	13	30860	2044206	100036	0

PA	Transmission	No. 515 Bear Creek, Pennsylvania	6	32000	423899	12281	0
PA	Transmission	No. 517 Benton, Pennsylvania	4	38500	245552	2459	0
PA	Transmission	No. 520 Salladasburg, Pennsylvania	7	35200	483089	10580	0
RI	Transmission	Burrillville Compressor Station, Burrillville, RI	5	22000	599629	11360	0
RI	Transmission	#265E - Burrillville, RI (Rise)	1	7170	332999	7550	0
VA*	Transmission	Loudoun, VA	9	15190	185470	10858	0
VA*	Transmission	Loudoun, VA	3	12000	205510	8434	0
VA*	Transmission	Leesburg, VA	3	14200	357748	10089	0
VA*	Transmission	No. 185 Manassas, Virginia	10	20000	1182138	74626	0
Total			721	2442801	55239677	2393711	414001868

*FERC 2 and 2A compressor stations in OTR area of VA

**2010 OTR Natural Gas Compressors
FERC Form 2 and Form 2A Data**

State	No. Compressors	Total Horsepower
CT	17	111630
MA	15	43832
MD	17	52250
ME	10	123125
NH	1	6053
NJ	35	139761
NY	123	406057
PA	472	1469533
RI	6	29170
VA*	25	61390

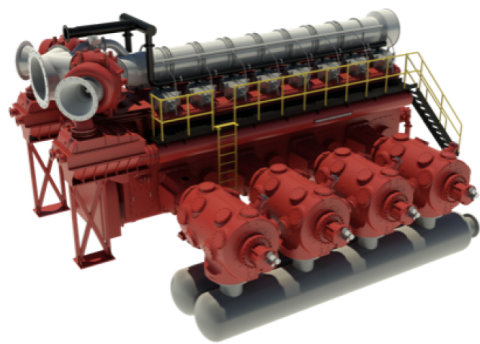
*OTR area of VA only



HOME / ENGINES & COMPRESSORS / UPGRADES
/ 0.5 G/BHP-HR NOX SOLUTION

0.5 g/bhp-hr NOx SOLUTION

CONTACT US



OVERVIEW UPGRADES OUR EXPERIENCE

OVERVIEW

WE ARE MARKET LEADERS

Cooper’s acquisition of HOERBIGER’s Engine Solutions division has allowed us to become the market leader once again in offering upgrades for your engine automation and emissions reduction. Cooper is very proud to offer a complete upgrade solution for 0.5 g/bhp-hr NOx emission that is available for all Clark, Cooper-Bessemer, and Ingersoll Rand slow speed engine models. This solution is fully backed by Cooper’s ownership of guarantee.

Our solution is built around two elements:

- Optimally designed forced air delivery system through either a turbocharger or a blower
- Electronic system upgrades for fuel, ignition, air/fuel ratio control, diagnostics, and balancing. These retrofits can be installed and operated independently with seamless ability to be integrated.

Complete Solution

OUR UPGRADES



OUR EXPERIENCE

UNITS OPERATING AT 0.5 g/bhp-hr NOx

Product Brand	Model	# Units	Location	Upgrade Technologies Applied
Clark	TLAD-8	1	Rhode Island	Turbocharger, HyperFuel, ePCC, HyperBalance, HyperLogic, PLC Automation
Cooper-Bessemer	16W330	1	Arkansas	Turbocharger, HyperFuel, ePCC, HyperBalance, HyperLogic, PLC Automation
Cooper-Bessemer	16W330	1	South Carolina	Turbocharger, HyperFuel, ePCC, HyperBalance, HyperLogic, PLC Automation
Cooper-Bessemer	GMV-10	4	Texas	Blower, HyperFuel, ePCC, HyperBalance, HyperLogic, PLC Automation
Cooper-Bessemer	GMV-10	6	Texas	Blower, HyperFuel, ePCC, HyperBalance, HyperLogic, PLC Automation
Cooper-Bessemer	GMVH-8	2	New Jersey	Turbocharger, HyperFuel, ePCC, HyperBalance, HyperLogic, PLC Automation
Cooper-Bessemer	GMWH-10C	2	Indiana	Turbocharger Re-Aero, HyperFuel, ePCC, HyperBalance, HyperLogic, PLC Automation
Ingersoll-Rand	KVG 410	6	Pennsylvania	ARC I, PLC automation, NSCR Catalyst

UNITS CAPABLE OF OPERATING AT 0.5 g/bhp-hr NOx

Product Brand	Model	# Units	Location	Upgrade Technologies Applied
Clark	HBA-8	3	New Jersey	Turbocharger, EFC, ePCC, HyperBalance
Clark	TCV-10	1	Pennsylvania	Hyperfuel, ePCC
Clark	TCV-10	2	Pennsylvania	Hyperfuel, ePCC

Product Brand	Model	# Units	Location	Upgrade Technologies Applied
Clark	TCV-10	3	Pennsylvania	Hyperfuel, ePCC
Clark	TCV-10	4	Pennsylvania	Hyperfuel, ePCC
Clark	TCVD-16	1	Louisiana	Hyperfuel, ePCC, HyperBalance
Cooper-Bessemer	12W330	1	Pennsylvania	HyperFuel, PCC, PLC automation
Cooper-Bessemer	GMVA-8	1	Pennsylvania	Turbocharger, HyperFuel, ePCC, HyperBalance, HyperLogic, PLC automation
Cooper-Bessemer	GMVH-8	2	New York	HyperFuel, PCC, HyperBalance



16250 Port Northwest Drive Houston, TX 77041

OUR COMPANY

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REGIONS & FACILITIES

(Adopted August 3, 1990)(Amended September 7, 1990)(Amended August 12, 1994)
(Amended December 9, 1994)(Amended November 14, 1997)(Amended June 3, 2005)
(Amended February 1, 2008)(Amended July 9, 2010)(Amended September 7, 2012)
(Amended December 4, 2015)(Amended June 3, 2016)(Amended November 1, 2019)

RULE 1110.2 EMISSIONS FROM GASEOUS- AND LIQUID-FUELED ENGINES

(a) Purpose

The purpose of Rule 1110.2 is to reduce Oxides of Nitrogen (NO_x), Volatile Organic Compounds (VOCs), and Carbon Monoxide (CO) from engines.

(b) Applicability

All stationary and portable engines over 50 rated brake horsepower (bhp) are subject to this rule.

(c) Definitions

For the purpose of this rule, the following definitions shall apply:

- (1) AGRICULTURAL STATIONARY ENGINE is a non-portable engine used for the growing and harvesting of crops or the raising of fowl or animals for the primary purpose of making a profit, providing a livelihood, or conducting agricultural research or instruction by an educational institution. An engine used for the processing or distribution of crops or fowl or animals is not an agricultural engine.
- (2) APPROVED EMISSION CONTROL PLAN is a control plan, submitted on or before December 31, 1992, and approved by the Executive Officer prior to November 14, 1997, that was required by subdivision (d) of this rule as amended September 7, 1990.
- (3) BREAKDOWN is a physical or mechanical failure or malfunction of an engine, air pollution control equipment, or related operating equipment that is not the result of operator error, neglect, improper operation or improper maintenance procedures, which leads to excess emissions beyond rule related emission limits or equipment permit conditions.
- (4) CERTIFIED SPARK-IGNITION ENGINE means engines certified by California Air Resources Board (CARB) to meet emission standards in accordance with Title 13, Chapter 9, Article 4.5 of the California Code of Regulations (CCR).
- (5) COMPRESSOR GAS LEAN-BURN ENGINE is a stationary gaseous-fueled two-stroke or four-stroke lean-burn engine used to compress natural gas or pipeline quality natural gas for delivery through a pipeline or into storage.

- (c) (6) EMERGENCY STANDBY ENGINE is an engine which operates as a temporary replacement for primary mechanical or electrical power during periods of fuel or energy shortage or while the primary power supply is under repair.
- (7) ENGINE is any spark- or compression-ignited internal combustion engine, including engines used for control of VOC's, but not including engines used for self-propulsion.
- (8) ESSENTIAL PUBLIC SERVICE includes any facility or operator as defined in Rule 1302.
- (9) EXEMPT COMPOUNDS are defined in South Coast AQMD Rule 102 – Definition of Terms.
- (10) FACILITY means any source or group of sources or other air contaminant emitting activities which are located on one or more contiguous properties within the South Coast AQMD, in actual physical contact or separated solely by a public roadway or other public right-of-way, and are owned or operated by the same person (or by persons under common control), or an outer continental shelf (OCS) source as determined in Section 55.2 of Title 40, Part 55 of the Code of Federal Regulations (40 CFR Part 55). Such above-described groups, if noncontiguous, but connected only by land carrying a pipeline, shall not be considered one facility. Sources or installations involved in crude oil and gas production in Southern California Coastal or OCS Waters and transport of such crude oil and gas in Southern California Coastal or OCS Waters shall be included in the same facility which is under the same ownership or use entitlement as the crude oil and gas production facility on-shore.
- (11) FORMER RECLAIM FACILITY means a facility, or any of its successors, that was in the Regional Clean Air Incentives Market as of January 5, 2018, as established in Regulation XX, that has received a final determination notification, and is no longer in the RECLAIM program.
- (12) LEAN-BURN ENGINE means an engine that operates with high levels of excess air and an exhaust oxygen concentration of greater than 4 percent.
- (13) LOCATION means any single site at a building, structure, facility, or installation. For the purpose of this definition, a site is a space occupied or to be occupied by an engine. For engines which are brought to a facility to perform maintenance on equipment at its permanent or ordinary location, each maintenance site shall be a separate location.

- (c) (14) NET ELECTRICAL ENERGY means the electrical energy produced by a generator, less the electrical energy consumed by any auxiliary equipment necessary to operate the engine generator and, if applicable, any heat recovery equipment, such as heat exchangers.
- (15) NON-RECLAIM FACILITY means a facility, or any of its successors, that was not in the Regional Clean Air Incentives Market as of January 5, 2018, as established in Regulation XX.
- (16) NON-ROAD ENGINE is any engine, defined under 40 CFR Part 89, that does not remain or will not remain at a location for more than 12 consecutive months, or a shorter period of time where such period is representative of normal annual source operation at a stationary source that resides at a fixed location for more than 12 months (e.g., seasonal operations such as canning facilities), and meets one of the following:
 - (A) Is used in or on a piece of equipment that is self-propelled or serves a dual purpose by both propelling itself and performing another function (such as a mobile crane); or
 - (B) Is used in or on a piece of equipment that is intended to be propelled while performing its function (such as lawn mowers and string trimmers); or
 - (C) By itself, or in or on a piece of equipment, is portable or transportable, meaning designed to be and capable of being carried or moved from one location to another. Transportability includes, but is not limited to, wheels, skids, carrying handles, dolly, trailer, platform or mounting.
- (17) OPERATING CYCLE means a period of time within which a round of regularly recurring events is completed, and cannot be stopped without the risk of endangering public safety or health, causing material damage to the equipment or product, or cannot be stopped due to technical constraints. Economic reasons alone will not be sufficient to extend this time period. The operating cycle includes batch processes that may start and finish several times within a twenty-four hour period, in which case each start to finish interval is considered a complete cycle.
- (18) OXIDES OF NITROGEN (NO_x) means nitric oxide and nitrogen dioxide.
- (19) PORTABLE ENGINE is an engine that, by itself or in or on a piece of equipment, is designed to be and capable of being carried or moved from one location to another. Indications of portability include, but are not

- (c) limited to, wheels, skids, carrying handles, dolly, trailer, platform or mounting. The operator must demonstrate the necessity of the engine being periodically moved from one location to another because of the nature of the operation.

An engine is not portable if:

- (A) The engine or its replacement remains or will reside at the same location for more than 12 consecutive months. Any engine, such as a back-up or stand-by engine, that replaces an engine at a location and is intended to perform the same function as the engine being replaced, will be included in calculating the consecutive time period. In that case, the cumulative time of both engines, including the time between the removal of the original engine and installation of the replacement engine, will be counted toward the consecutive time period; or
- (B) The engine remains or will reside at a location for less than 12 consecutive months where such a period represents the full length of normal annual source operations such as a seasonal source; or
- (C) The engine is removed from one location for a period and then it or its equivalent is returned to the same location thereby circumventing the portable engine residence time requirements.

The period during which the engine is maintained at a designated storage facility shall be excluded from the residency time determination.

- (20) **RATED BRAKE HORSEPOWER (bhp)** is the rating specified by the manufacturer, without regard to any derating, and listed on the engine nameplate.
- (21) **RECLAIM FACILITY** means a facility, or any of its successors, that was in the Regional Clean Air Incentives Market as of January 5, 2018, as established in Regulation XX.
- (22) **RICH-BURN ENGINE WITH A THREE-WAY CATALYST** means an engine designed to operate near stoichiometric conditions with a catalytic control device that simultaneously reduces emissions of NO_x, CO and VOC.
- (23) **STATIONARY ENGINE** is an engine which is either attached to a foundation or if not so attached, does not meet the definition of a portable or non-road engine and is not a motor vehicle as defined in Section 415 of the California Vehicle Code.

- (c) (24) TIER 2 AND TIER 3 DIESEL ENGINES mean engines certified by CARB to meet Tier 2 or Tier 3 emission standards in accordance with Title 13, Chapter 9, Article 4 of the CCR.
- (25) USEFUL HEAT RECOVERED means the waste heat recovered from the engine exhaust and/or cooling system that is put to productive use. The waste heat recovered may be assumed to be 100% useful unless the hot water, steam or other medium is vented to the atmosphere, or sent directly to a cooling tower or other unproductive use.
- (26) VOLATILE ORGANIC COMPOUND (VOC) is as defined in Rule 102.
- (d) Requirements
 - (1) Stationary Engines:
 - (A) Operators of stationary engines with an amended Rule 1110.1 Emission Control Plan submitted by July 1, 1991, or an Approved Emission Control Plan, designating the permanent removal of engines or the replacement of engines with electric motors, in accordance with subparagraph (d)(1)(B), shall do so by December 31, 1999, or not operate the engines on or after December 31, 1999 in a manner that exceeds the emission concentration limits listed in Table I:

TABLE I ALTERNATIVE TO ELECTRIFICATION CONCENTRATION LIMITS		
NO _x (ppmvd) ¹	VOC (ppmvd) ²	CO (ppmvd) ¹
11	30	70

¹ Parts per million by volume, corrected to 15% oxygen on a dry basis and averaged over 15 minutes.

² Parts per million by volume, measured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

- (B) The operator of any other stationary engine not covered by subparagraph (d)(1)(A) shall:
 - (i) Remove such engine permanently from service or replace the engine with an electric motor, or alternatively comply

- (d) with the following, if applicable:
- (ii) Comply with the applicable emission concentration limits listed in either Table II or Table III-A or B, or technologically achievable case-by-case VOC or CO emission concentration limits approved by the Executive Officer pursuant to clause (d)(1)(B)(vii), averaged over 15 minutes or other averaging time period allowed by clauses (d)(1)(B)(iii) through (d)(1)(B)(v);
 - (iii) Use an averaging time approved by the Executive Officer for an engine that uses non-pipeline quality natural gas that has demonstrated that due to the varying heating value of the gas a longer averaging time was necessary. The fixed-interval averaging time shall not exceed six hours for any of the concentration limits of Table II, unless an engine is subject to an existing permit condition allowing for an averaging time greater than six hours. Non-pipeline quality natural gas is a gas that does not meet the gas specifications of the local gas utility and is not supplied to the local gas utility;
 - (iv) Use a fixed-interval averaging time of one hour for engines equipped with a Continuous Emissions Monitoring System (CEMS), to demonstrate compliance with the emission concentration limits of Table II or Table III-B;
 - (v) Use a fixed-interval averaging time of three hours for compressor gas lean-burn engines equipped with selective catalytic reduction pollution control equipment and a CEMS, to demonstrate compliance with the NO_x emission concentration limit of Table II;
 - (vi) Comply with the emission concentration limits listed in Table II for Low-Use Engines. A Low-Use engine is an engine that operates less than 500 hours per year or uses less than 1×10^9 British Thermal Units (Btus) per year (higher heating value) of fuel;
 - (vii) Comply with any technologically achievable case-by-case CO and VOC limits that were approved by the Executive Officer in lieu of the concentration limits in Table II

- (d) effective on and after July 1, 2011 for a two-stroke engine equipped with an oxidation catalyst and insulated exhaust ducts and catalyst housing that has demonstrated that the CO and VOC limits effective on and after July 1, 2011 were not achievable. The case-by-case limits shall not exceed 250 ppmvd VOC and 2000 ppmvd CO, but must comply with the applicable NO_x concentration limit in Table II.

TABLE II		
CONCENTRATION LIMITS FOR LOW-USE ENGINES		
NO _x (ppmvd) ¹	VOC (ppmvd) ²	CO (ppmvd) ¹
bhp ≥ 500: 36 bhp < 500: 45	250	2000
CONCENTRATION LIMITS		
EFFECTIVE JULY 1, 2011		
NO _x (ppmvd) ¹	VOC (ppmvd) ²	CO (ppmvd) ¹
11	30	250

¹ Parts per million by volume, corrected to 15% oxygen on a dry basis.

² Parts per million by volume, measured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

- (C) The operator of any stationary engine fired by landfill or digester gas (biogas) shall not operate the engine in a manner that exceeds the emission concentration limits of Table III-A, provided that the facility monthly average biogas usage by the biogas engine is 90% or more, based on the higher heating value of the fuels used. The calculation of the monthly facility biogas use percentage may exclude natural gas fired during: any electrical outage at the facility; a Stage 2 or higher electrical emergencies called by the California Independent System Operator Corporation; and when a sewage treatment plant activates an Emergency Operations Center or Incident Command System, as part of an emergency response

- (d) plan, because of either high influent flows caused by precipitation or a disaster.

TABLE III-A CONCENTRATION LIMITS FOR LANDFILL AND DIGESTER GAS (BIOGAS)-FIRED LOW-USE ENGINES		
NO _x (ppmvd) ¹	VOC (ppmvd) ²	CO (ppmvd) ¹
bhp ≥ 500: 36 x ECF ³ bhp < 500: 45 x ECF ³	Landfill Gas: 40 Digester Gas: 250 x ECF ³	2000
TABLE III-B CONCENTRATION LIMITS FOR LANDFILL AND DIGESTER GAS (BIOGAS)-FIRED ENGINES EFFECTIVE JANUARY 1, 2017		
NO _x (ppmvd) ¹	VOC (ppmvd) ²	CO (ppmvd) ¹
11	30	250

¹ Parts per million by volume, corrected to 15% oxygen on a dry basis.

² Parts per million by volume, measured as carbon, corrected to 15% oxygen on a dry basis and averaged over the sampling time required by the test method.

³ ECF is the efficiency correction factor.

The ECF shall be 1.0 unless:

- (i) The engine operator has measured the engine's net specific energy consumption (q_a), in compliance with ASME Performance Test Code PTC 17 -1973, at the average load of the engine; and
- (ii) The ECF-corrected emission limit is made a condition of the engine's permit to operate.

The ECF is as follows:

$$\text{ECF} = \frac{9250 \text{ Btus/hp-hr}}{\text{Measured } q_a \text{ in Btus/hp-hr}}$$

Measured q_a shall be based on the lower heating value of the fuel.
ECF shall not be less than 1.0.

- (d) The Executive Officer may approve the burning of more than 10% natural gas in a landfill or digester gas-fired engine, when it is necessary, if: the only alternative to limiting natural gas to 10% would be shutting down the engine and flaring more landfill or digester gas; or the engine requires more natural gas in order for a waste heat recovery boiler to provide enough thermal energy to operate a sewage treatment plant, and other boilers at the facility are unable to provide the necessary thermal energy.
- (D) Notwithstanding the provisions of subparagraph (d)(1)(B), the operator of any stationary engine fired by landfill or digester gas (biogas) shall not operate the engine in a manner that exceeds the emission concentration limits of Table III.
- (E) Biogas engine operators that establish to the satisfaction of the Executive Officer that they have complied with the emissions limits of Table III-B by January 1, 2015 will have their respective engine permit application fees refunded.
- (F) For the City of San Bernardino, Orange County Sanitation District, and Eastern Municipal Water District that commenced and implemented technology demonstration projects prior to January 1, 2015, all their biogas engines shall have until January 1, 2018 to comply with the requirements of Table III-B.
- (G) Once an engine complies with the concentration limits as specified in Table III-B, there shall be no limit on the percentage of natural gas burned.
- (H) The concentration limits effective as specified in Table III-A shall apply to engines that are biogas-fired Low-Use engines. A biogas-fired Low-Use engine is an engine that operates fewer than 500 hours per year or uses less than 1×10^9 Btus per year (higher heating value) of fuel.
- (I) An operator of a biogas engine with a CEMS shall meet either:
- (i) The NO_x and CO limits of Table III-B, averaged pursuant to the specified averaging provisions in subparagraph (d)(1)(B);
 - (ii) The emission limits at or below 11 ppmvd for NO_x and 250 ppmvd for CO (if CO is selected for averaging), each

- (d) corrected to 15% O₂ and averaged over a 24-hour fixed interval, with the emission limits and averaging time specified as a condition in the engine's permit to operate on or before November 1, 2019; or
- (iii) The emission limits at or below 9.9 ppmvd for NO_x and 225 ppmvd for CO (if CO is selected for averaging), each corrected to 15% O₂ and averaged over a 48-hour fixed interval, with emission limits and averaging time specified as a condition in the engine's permit to operate.
- (J) The operator of any new engine subject to subparagraph (e)(1)(B) shall:
 - (i) Comply with the requirements of Best Available Control Technology in accordance with Regulation XIII if the engine requires a South Coast AQMD permit; or
 - (ii) Not operate the engine in a manner that exceeds the emission concentration limits in Table I if the engine does not require a South Coast AQMD permit.
- (K) By February 1, 2009, the operator of a spark-ignited engine without a Rule 218-approved continuous emission monitoring system (CEMS) or a Regulation XX (RECLAIM)-approved CEMS shall equip and maintain the engine with an air-to-fuel ratio controller with an oxygen sensor and feedback control, or other equivalent technology approved by the Executive Officer, CARB and EPA.
- (L) New Non-Emergency Electrical Generators
 - (i) All new non-emergency engines driving electrical-generators shall comply with the following emission standards in lbs/MW-hr:

(d)

TABLE IV EMISSION STANDARDS FOR NEW ELECTRICAL GENERATION DEVICES		
Pollutant	Emission Standard (lbs/MW-hr)¹	Concentration Limit³ (ppmvd)⁴
NO _x	0.070	2.5
CO	0.20	12
VOC	0.10 ²	10

- ¹ The averaging time of the emission standard for VOC is the sampling time required by the test method.
- ² Mass emissions of VOC shall be calculated using a ratio of 16.04 pounds of VOC per lb-mole of carbon.
- ³ Concentration limit is calculated using a 40% engine efficiency and no applied thermal credit.
- ⁴ Parts per million by volume, corrected to 15% oxygen on a dry basis.

- (ii) Engines subject to this subparagraph that produce combined heat and electrical power may include one megawatt-hour (MW-hr) for each 3.4 million Btus of useful heat recovered (MW_{th}-hr), in addition to each MW-hr of net electricity produced (MW_e-hr). The compliance of such engines shall be based on the following equation:

$$\frac{\text{Lbs}}{\text{MW-hr}} = \frac{\text{Lbs}}{\text{MW}_e\text{-hr}} \times \text{Electrical Energy Factor (EEF)}$$

Where:

Lbs/MW-hr = The calculated emissions standard.

Lbs/MW_e-hr = The short-term engine emission limit in pounds per MWe-hr of net electrical energy produced.

EEF = The annual MW_e-hrs of net electrical energy produced divided by the sum of annual MW_e-hrs plus annual MW_{th}-hrs of useful heat recovered.

- (iii) For combined heat and power engines, the short-term

- (d) emission limits in lbs/MW_e-hr and the maximum allowed annual EEF must be selected by operator and stated on the operating permit.
- (iv) The requirements of this subparagraph shall apply to NO_x emissions from new non-emergency engines driving electrical-generators subject to Regulation XX (RECLAIM).
- (v) This subparagraph does not apply to: engines installed prior to February 1, 2008; engines issued a permit to construct prior to February 1, 2008 and installed within 12 months of the date of the permit to construct; engines for which an application is deemed complete by October 1, 2007; engines installed by an electric utility on Santa Catalina Island; engines installed at remote locations without access to natural gas and electric power; engines used to supply electrical power to ocean-going vessels while at berth, prior to January 1, 2014; or landfill or digester gas-fired engines that meet the requirements of subparagraph (d)(1)(C).
- (vi) For engines driving electrical generators and operating with a CEMS, a fixed-interval averaging time of one hour shall be used to demonstrate compliance with the NO_x and CO emission standard requirements of Table IV in lbs/MW-hr. For engines driving electrical generators and operating without a CEMS, the NO_x and CO emission standard requirements of Table IV in lbs/MW-hr shall be averaged over 15 minutes.
- (vii) Owners and operators of new engines installed prior to January 1, 2024 with no ammonia emissions from add-on control equipment and where NO_x emissions meet the concentration limit of Table IV at all times may elect to apply for and comply with the concentration limits of Table IV, expressed in ppmvd, except an alternative VOC concentration limit that is equal to or less than 25 ppmvd may be complied with. The Executive Officer shall accumulate daily VOC emissions in excess of the concentration limit of Table IV based on the permitted VOC

- (d) limits from each such engine and shall not approve any additional permit for such engine that will cause the total accumulated daily VOC emissions to exceed 45 lbs per day. Any new installation on or after January 1, 2024 shall comply with the VOC concentration limit in Table IV in ppmvd.

(2) Portable Engines:

- (A) The operator of any portable engine generator subject to this rule shall not use the portable generator for:
- (i) Power production into the electric grid, except to maintain grid stability during an emergency event or other unforeseen event that affects grid stability; or
 - (ii) Primary or supplemental power to a building, facility, stationary source, or stationary equipment, except during unforeseen interruptions of electrical power from the serving utility, maintenance and repair operations, and remote operations where grid power is unavailable. For interruptions of electrical power, the operation of a portable generator shall not exceed the time of the actual interruption of power.

This subparagraph shall not apply to a portable generator that complies with emission concentration limits of Table I and the other requirements in this rule applicable to stationary engines.

- (B) The operator of any portable diesel engine shall comply with the applicable requirements of the Subchapter 7.5 Airborne Toxic Control Measures for diesel particulate matter in Chapter 1, Division 3, Title 17 of the California Code of Regulations.
- (C) The operator of any portable spark-ignited engine shall comply with the applicable requirements of the Large Spark Ignition Engine Fleet Requirements, Article 2, Chapter 15, Division 3, Title 13 of the California Code of Regulations.

(e) Compliance

(1) Agricultural Stationary Engines:

- (A) The operator of any agricultural stationary engine subject to this rule and installed or issued a permit to construct prior to June 3,

- (e) 2005 shall comply with subparagraph (d)(1)(B) and the other applicable provisions of this rule in accordance with the compliance schedules in Table V:

TABLE V COMPLIANCE SCHEDULES FOR STATIONARY AGRICULTURAL ENGINES		
Action Required	Tier 2 and Tier 3 Diesel Engines, Certified Spark-Ignition Engines, and All Engines at Facilities with Actual Emissions Less Than the Amounts in the Table of Rule 219(q)	Other Engines
Submit notification of applicability to the Executive Officer	January 1, 2006	January 1, 2006
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	March 1, 2009	September 1, 2007
Initiate construction of engine modifications, control equipment, or replacement engines	September 30, 2009, or 30 days after the permit to construct is issued, whichever is later	March 30, 2008, or 30 days after the permit to construct is issued, whichever is later
Complete construction and comply with applicable requirements	January 1, 2010, or 60 days after the permit to construct is issued, whichever is later	July 1, 2008, or 60 days after the permit to construct is issued, whichever is later
Complete initial source testing	March 1, 2010, or 120 days after the permit to construct is issued, whichever is later	September 1, 2008, or 120 days after the permit to construct is issued, whichever is later

- (e) The notification of applicability shall include the following for each engine:
 - (i) Name and mailing address of the operator
 - (ii) Address of the engine location
 - (iii) Manufacturer, model, serial number, and date of manufacture of the engine
 - (iv) Application number
 - (v) Engine type (diesel, rich-burn spark-ignition or lean-burn spark-ignition)
 - (vi) Engine fuel type
 - (vii) Engine use (pump, compressor, generator, or other)
 - (viii) Expected means of compliance (engine replacement, control equipment installation, or electrification)
- (B) The operator of any new agricultural stationary engine that is not subject to the compliance schedule of subparagraph (e)(1)(A) for existing engines shall comply with the requirements of subparagraph (d)(1)(J) immediately upon installation.
- (2) Non-Agricultural Stationary Engines:
 - (A) The operator of any stationary engine not meeting the requirements of subparagraph (d)(1)(B) or (d)(1)(C) that go into effect in 2010 or later, shall comply with the compliance schedule in Table VI.
 - (B) The operator of any stationary engine that elects to amend a permit to operate to incorporate ECF-adjusted emission limits shall submit to the Executive Officer an application for a change of permit conditions by August 1, 2008, and comply with emission limits of the previous version of this rule until February 1, 2009 when the engine shall be in compliance with the emission limits of this rule.
 - (C) The operator of any stationary engine that is required to add operating restrictions to a permit to operate to meet the requirements of this rule shall submit to the Executive Officer an application for a change of permit conditions by August 1, 2008.

(e)

TABLE VI COMPLIANCE SCHEDULE FOR NON -AGRICULTURAL STATIONARY ENGINES	
Action Required	Applicable Compliance Date
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	Twelve months before the final compliance date
Initiate construction of engine modifications, control equipment, or replacement engines	Three months before the final compliance date, or 60 days after the permit to construct is issued, whichever is later
Complete construction and comply with applicable requirements	The final compliance date, or 120 days after the permit to construct is issued, whichever is later
Complete initial source testing	60 days after the final compliance date in subparagraph (d)(1)(B) or (d)(1)(C), or 180 days after the permit to construct is issued, whichever is later

(3) Stationary Engine CEMS

- (A) The operator of any stationary engine with an existing CEMS shall commence the reporting required by Rule 218 Subdivision (f) on January 1, 2008. The first summary report for the six months ending June 30, 2008 shall be due on July 30, 2008.
- (B) The operator of any stationary engine that is required to modify an existing CEMS or install a CEMS on an existing engine shall comply with the compliance schedule in Table VII. Public agencies shall be allowed one year more than the dates in Table VII, except for biogas engines.
- (C) The operator of any stationary engine that is located at a RECLAIM or former RECLAIM facility that is required to modify an existing CEMS or install a CEMS on an existing engine that is subject to paragraph (f)(1) shall comply with the compliance schedule in Table VII except that the operator shall submit to the

- (e) Executive Officer applications for a new or modified CEMS within 90 days of becoming a former RECLAIM facility.
- (i) For engines at a RECLAIM or former RECLAIM facility, installation of a CEMS is required concurrently with the installation of retrofit control technologies or new engine replacements to meet the requirements of paragraph (d)(1).

TABLE VII COMPLIANCE SCHEDULE FOR NEW OR MODIFIED CEMS ON EXISTING ENGINES			
Action Required	Applicable Compliance Dates For:		
	Non-Biogas Engines Rated at 750 bhp or More	Non-Biogas Engines Rated at Less than 750 bhp	Biogas Engines*
Submit to the Executive Officer applications for new or modified CEMS	August 1, 2008	August 1, 2009	January 1, 2011
Complete installation and commence CEMS operation, calibration, and reporting requirements	Within 180 days of initial approval	Within 180 days of initial approval	Within 180 days of initial approval
Complete certification tests	Within 90 days of installation	Within 90 days of installation	Within 90 days of installation
Submit certification reports to Executive Officer	Within 45 days after tests are completed	Within 45 days after tests are completed	Within 45 days after tests are completed
Obtain final approval of CEMS	Within 1 year of initial approval	Within 1 year of initial approval	Within 1 year of initial approval

* A biogas engine is one that is subject to the emission limits of Table III.

- (e) (4) Stationary Engine Inspection and Monitoring (I&M) Plans:
The operator of stationary engines subject to the I&M plan provisions of subparagraph (f)(1)(D) shall:
- (A) By August 1, 2008, submit an initial I&M plan application to the Executive Officer for approval;
 - (B) By December 1, 2008, implement an approved I&M plan or the I&M plan as submitted if the plan is not yet approved.
- Any operator of 15 or more stationary engines subject to the I&M plan provisions shall comply with the above schedule for at least 50% of engines, and for the remaining engines shall:
- (C) By February 1, 2009, submit an initial I&M plan application to the Executive Officer for approval;
 - (D) By June 1, 2009, implement an approved I&M plan or the I&M plan as submitted if the plan is not yet approved.
- (5) Stationary Engine Air-to-Fuel Ratio Controllers
- (A) The operator of any stationary engine that does not have an air-to-fuel ratio controller, as required by subparagraph (d)(1)(K), shall comply with those requirements in accordance with the compliance schedule in Table V, except that the application due date is no later than May 1, 2008 and the initial source testing may be conducted at the time of the testing required by subparagraph (f)(1)(C).
 - (B) The operator of any stationary engine that has the air-to-fuel ratio controller required by subparagraph (d)(1)(K), but it is not listed on the permit to operate, shall submit to the Executive Officer an application to amend the permit by April 1, 2008.
 - (C) The operator of more than five engines that do not have air-to-fuel ratio controllers may take an additional three months, to May 1, 2009, to install the equipment on up to 50% of the affected engines.
- (6) New Stationary Engines
- The operator of any new stationary engine issued a permit to construct after February 1, 2008 shall comply with the applicable I&M or CEMS requirements of this rule when operation commences. If applicable, the operator shall provide the required information in subparagraph (f)(1)(D) to the Executive Officer prior to the issuance of the permit to construct so that the I&M procedures can be included in the permit. A separate I&M

- (e) plan application is not required.
- (7) **Biogas Engines**

For any biogas engine for which the operator applies to the Executive Officer by April 1, 2008 for a change of permit conditions for ECF-corrected emission limits, or the approval to burn more than 10 percent natural gas in accordance with subparagraph (d)(1)(C), the biogas engine shall not be subject to the initial concentration limits of Tables II or III until August 1, 2008, provided the operator continues to comply with all emission limits in effect prior to February 1, 2008.
- (8) **Compliance Schedule Exception**

If an engine operator submits to the Executive Officer an application for an administrative change of permit conditions to add a permit condition that causes the engine permit to expire by the effective date of any requirement of this rule, then the operator is not required to comply with the earlier steps required by this subdivision for that requirement. The effective date for the CEMS requirements shall be one year after the date that a CEMS application is due.
- (9) **Exceedance of Usage Limits**
 - (A) If an engine was initially exempt from the new concentration limits in subparagraph (d)(1)(B) or subparagraph (d)(1)(C) that take effect on or after July 1, 2011 because of low engine use but later exceeds the low-use criteria, the operator shall bring the engine into compliance with the rule in accordance with the schedule in Table VI with the final compliance date in Table VI being twelve months after the conclusion of the first twelve-month period for which the engine exceeds the low-use criteria.
 - (B) If engines that were initially exempt from new CEMS by the low-use criterion in subclause (f)(1)(A)(ii)(I) later exceed that criterion, the operator shall install CEMS on those engines in accordance with the schedule in Table VII, except that the date for submitting the CEMS application in Table VII shall be six months after the conclusion of the first twelve-month period for which the engines exceed the criterion.
- (10) **RECLAIM or Former RECLAIM Facilities**

The owner or operator of a RECLAIM or former RECLAIM facility with any unit(s) subject to subdivision (d) shall meet the applicable NO_x

- (e) emission limit in Table II or III-B in accordance with the schedule specified in Rule 1100 – Implementation Schedule for NO_x Facilities.
- (f) Monitoring, Testing, Recordkeeping and Reporting
 - (1) Stationary engines:

The operator of any engine subject to the provisions of paragraph (d)(1) of this rule shall meet the following requirements:

 - (A) Continuous Emission Monitoring
 - (i) For engines of 1000 bhp and greater and operating more than two million bhp-hr per calendar year, a NO_x and CO CEMS shall be installed, operated and maintained in calibration to demonstrate compliance with the emission limits of this rule.
 - (ii)
 - (I) For facilities with engines subject to paragraph (d)(1), having a combined rating of 1500 bhp or greater at the same location, and having a combined fuel usage of more than 16×10^9 Btus per year (higher heating value), CEMS shall be installed, operated and maintained in calibration to demonstrate compliance of those engines with the applicable NO_x and CO emission limits of this rule.
 - (II) Any engine that as of October 1, 2007 is located within 75 feet of another engine (measured from engine block to engine block) is considered to be at the same location. Operators of new engines shall not install engines farther than 75 feet from another engine unless the operator demonstrates to the Executive Officer that operational needs or space limitations require it.
 - (III) The following engines shall not be counted toward the combined rating or required to have a CEMS by this clause: engines rated at less than 500 bhp; standby engines that are limited by permit conditions to only operate when other primary engines are not operable; engines that are limited by permit conditions to operate less than 1000 hours

- (f) per year or a fuel usage of less than 8×10^9 Btus per year (higher heating value of all fuels used); engines that are used primarily to fuel public natural gas transit vehicles and that are required by a permit condition to be irreversibly removed from service by December 31, 2014; and engines required to have a CEMS by the previous clause. A CEMS shall not be required if permit conditions limit the simultaneous use of the engines at the same location in a manner to limit the combined rating of all engines in simultaneous operation to less than 1500 bhp.
- (IV) For engines rated below 1000 bhp, the CEMS may be time shared by multiple engines.
- (V) Operation of engines by the electric utility in the Big Bear Lake area during the failure of a transmission line to the utility may be excluded from an hours-per-year or fuel usage limit that is elected by the operator pursuant to subclause (f)(1)(A)(ii)(III).
- (VI) In lieu of complying with subclause (f)(1)(A)(ii)(I), an operator that is a public agency, or is contracted to operate engines solely for a public agency, may comply with the Inspection and Monitoring Plan requirements of subparagraph (f)(1)(D), except that the operator shall conduct diagnostic emission checks at least weekly or every 150 operating hours, whichever occurs later. If any such engine is found to exceed an applicable NO_x or CO limit by a source test required by subparagraph (f)(1)(C) or South Coast AQMD test using a portable analyzer on three or more occasions in any 12-month period, the operator shall comply with the CEMS requirements of this subparagraph for such engine in accordance with the compliance schedule of Table VII, except that the operator shall submit a CEMS application to

- (f) the Executive Officer within six months of the third exceedance.
- (iii) All CEMS required by this rule shall:
- (I) Comply with the applicable requirements of Rules 218 and 218.1, including equipment specifications and certification, operating, recordkeeping, quality assurance and reporting requirements, except as otherwise authorized by this rule;
 - (II) Include equipment that measures and records exhaust gas concentrations, both uncorrected and corrected to 15 percent oxygen on a dry basis; and
 - (III) Have data gathering and retrieval capability approved by the Executive Officer
- (iv) The operator of an engine that is required to install CEMS may request the Executive Officer to approve an alternative monitoring device (or system components) to demonstrate compliance with the emission limits of this rule. The applicant shall demonstrate to the Executive Officer that the proposed alternative monitoring device is at a minimum equivalent in relative accuracy, precision, reliability, and timeliness to a CEMS for that engine, according to the criteria specified in 40 CFR Part 75 Subpart E. In lieu of the criteria specified in 40 CFR Part 75 Subpart E, substitute criteria is acceptable if the applicant demonstrates to the Executive Officer that the proposed alternative monitoring device is at minimum equivalent in relative accuracy, precision, reliability, and timeliness to a CEMS for that engine. Upon approval by the Executive Officer, the substitute criteria shall be submitted to EPA as an amendment to the State Implementation Plan (SIP). If the alternative monitoring device is denied or fails to be recertified, a CEMS shall be required.
- (v) Notwithstanding the requirements of Rules 218 and 218.1, operators of engines that are required to install a CEMS by clause (f)(1)(A)(ii) may:

- (f)
 - (I) Store data electronically without a strip chart recorder, but there shall be redundant data storage capability for at least 15 days of data. The operator must demonstrate that both sets of data are equivalent.
 - (II) Conduct relative accuracy testing on the same schedule for source testing in clause (f)(1)(C)(i), instead of annually. The minimum sampling time for each test is 15 minutes.
- (vi) Notwithstanding the requirements of Rules 218 and 218.1, operators of engines that are required to install a CEMS by clause (f)(1)(A)(ii), and that are to be monitored by a timeshared CEMS, may:
 - (I) Monitor an engine with the CEMS for 15 consecutive minutes, purge for the minimum required purge time, then monitor the next engine for 15 consecutive minutes. The CEMS shall operate continuously in this manner, except for required calibrations.
 - (II) Record the corrected and uncorrected NO_x, CO and diluent data at least once per minute and calculate and record the 15-minute average corrected concentrations for each sampling period.
 - (III) Have sample lines to each engine that are not the same length. The purge time will be based on the sample line with the longest response time. Response times shall be checked during cylinder gas audits. Sample lines shall not exceed 100 feet in length.
 - (IV) Conduct a minimum of five tests for each engine during relative accuracy tests.
 - (V) Perform a cylinder gas audit every calendar quarter on each engine, except for engines for which relative accuracy testing was conducted that quarter.
 - (VI) Exclude monitoring of nitrogen dioxide (NO₂) for rich-burn engines, unless source testing

- (f) demonstrates that NO₂ is more than 10 percent of total NO_x.
- (VII) Conduct daily calibration error (CE) tests by injecting calibration gases at the analyzers, except that at least once per week the CE test shall be conducted by injecting calibration gases as close to the probe tip as practical.
- (VIII) Stop operating and calibrating the CEMS during any period that the operator has a continuous record that the engine was not in operation.
- (vii) A CO CEMS shall not be required for lean-burn engines or an engine that is subject to Regulation XX (RECLAIM), and not required to have a NO_x CEMS by that regulation.
- (viii) Notwithstanding the requirements of this paragraph and paragraph (c)(2) of Rule 2012, an operator may take an existing NO_x CEMS out of service for up to two weeks (cumulative) in order to modify the CEMS to add CO monitoring.
- (ix) In lieu of clause (f)(1)(A)(i), an Essential Public Service or a contractor for an Essential Public Service that is operating a biogas engine of 1000 bhp and greater and less than 1200 bhp, may alternatively comply with the Inspection and Monitoring Plan requirements of subparagraph (f)(1)(D), provided the operator conducts diagnostic emission checks at least weekly or every 150 operating hours, whichever occurs later.
- (x) If an Essential Public Service or a contractor for an Essential Public Service has elected to comply with the Inspection and Monitoring Plan provisions pursuant to clause (f)(1)(A)(ix) for biogas engines is found to exceed an applicable NO_x or CO limit by a source test required by subparagraph (f)(1)(C) or South Coast AQMD test using a portable analyzer on three or more occasions in any 12-month period, the operator shall comply with the CEMS requirements of clause (f)(1)(A)(i) for such biogas engine in accordance with the compliance schedule of Table VII

- (f) except that the operator shall submit a CEMS application to the Executive Officer within six months of the third exceedance.
- (B) Elapsed Time Meter
Maintain an operational non-resettable totalizing time meter to determine the engine elapsed operating time.
- (C) Source Testing
 - (i) Effective August 1, 2008, conduct source testing for NO_x, VOC reported as carbon, and CO concentrations (concentrations in ppm by volume, corrected to 15 percent oxygen on dry basis) at least once every two years from the date of the previous source test, no later than the last day of the calendar month that the test is due, or every 8,760 operating hours, whichever occurs first. Relative accuracy tests required by Rule 218.1 or 40 CFR Part 75 Subpart E shall satisfy this requirement for those pollutants monitored by a CEMS. The above source test frequency may be reduced to once every three years if the engine has operated less than 2,000 hours since the last source test. If the engine has not been operated before the date a source test is due, the source test shall be conducted by the end of seven consecutive days or 15 cumulative days of resumed operation. The operator of the engine shall keep sufficient operating records to demonstrate that it meets the requirements for extension of the source testing deadlines.
 - (ii) Conduct source testing for at least 30 minutes during normal operation (actual duty cycle). This test shall not be conducted under a steady-state condition unless it is the normal operation. In addition, conduct source testing for NO_x and CO emissions for at least 15 minutes at: an engine's actual peak load, or the maximum load that can be practically achieved during the test, and; at actual minimum load, excluding idle, or the minimum load that can be practically achieved during the test. These additional two tests are not required if the permit limits the engine to operating at one defined load, $\pm 10\%$. No pre-tests for

- (f) compliance are permitted. The emission test shall be conducted at least 40 operating hours, or at least 1 week, after any engine servicing or tuning. If an emission exceedance is found during any of the three phases of the test, that phase shall be completed and reported. The operator shall correct the exceedance, and the source test may be immediately resumed. Relative accuracy tests required by Rule 218.1 or 40 CFR Part 75 Subpart E shall satisfy this requirement for those pollutants monitored by a CEMS for all applicable operating loads specified in this clause (f)(1)(C)(ii).
- (iii) Use a contractor to conduct the source testing that is approved by the Executive Officer under the Laboratory Approval Program for the necessary test methods.
- (iv) Submit a source test protocol to the Executive Officer for written approval at least 60 days before the scheduled date of the test. The source test protocol shall include the name, address and phone number of the engine operator and a South Coast AQMD-approved source testing contractor that will conduct the test, the application and permit number(s), emission limits, a description of the engine(s) to be tested, the test methods and procedures to be used, the number of tests to be conducted and under what loads, the required minimum sampling time for the VOC test, based on the analytical detection limit and expected VOC levels, and a description of the parameters to be measured in accordance with the I&M plan required by subparagraph (f)(1)(D). The source test protocol shall be approved by the Executive Officer prior to any testing. The operator is not required to submit a protocol for approval if: there is a previously approved protocol that meets these requirements; the engine has not been altered in a manner that requires a permit alteration; and emission limits have not changed since the previous test. If the operator submits the protocol by the required date, and the Executive Officer takes longer than 60 days to approve the protocol, the

- (f) operator shall be allowed the additional time needed to conduct the test.
- (v) Provide the Executive Officer at least 30 days prior notice of any source test to afford the Executive Officer the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the scheduled performance test, the engine operator shall notify the Executive Officer as soon as possible of any delay in the original test date, either by providing at least seven days prior notice of the rescheduled date of the performance test, or by arranging a rescheduled date with the Executive Officer by mutual agreement.
- (vi) Submit all source test reports, including a description of the equipment tested, to the Executive Officer within 60 days of completion of the test.
- (vii) By February 1, 2009, provide, or cause to be provided, source testing facilities as follows:
 - (I) Sampling ports adequate for the applicable test methods. This includes constructing the air pollution control system and stack or duct such that pollutant concentrations can be accurately determined by applicable test methods;
 - (II) Safe sampling platform(s), scaffolding or mechanical lifts, including safe access, that comply with California General Safety Orders. Agricultural stationary engines are excused from this subclause if they are in remote locations without electrical power;
 - (III) Utilities for sampling and testing equipment. Agricultural stationary engines are exempt from this subclause if they are on wheels and moved to storage during the off season.
- (D) Inspection and Monitoring (I&M) Requirements
 - (i) I&M Plan. The operator shall:
 - (I) Submit to the Executive Officer for written approval

- (f) an I&M plan. One plan application is required for each facility that does not have a NO_x and CO CEMS for each engine. The I&M plan shall include all items listed in Attachment 1. The owner or operator may request an alternative item(s) in Attachment 1 that is determined by the Executive Officer to be equivalent in meeting the same objectives.
 - (II) Upon written approval by the Executive Officer, implement the I&M plan as approved.
 - (III) Submit an I&M plan for approval to the Executive Officer for a plan revision before any change in I&M plan operations can be implemented. The operator shall apply for a plan revision prior to any change in emission limits or control equipment.
- (ii) Diagnostic emission checks by a portable NO_x, CO, and oxygen analyzer shall be conducted at least weekly or every 150 engine operating hours, whichever occurs later.
 - (I) If an engine is in compliance for three consecutive diagnostic emission checks, without any adjustments to the oxygen sensor set points, then the engine may be checked monthly or every 750 engine operating hours, whichever occurs later, until there is a noncompliant diagnostic emission check or, for rich-burn engines with three-way catalysts, until the oxygen sensor is replaced. When making adjustments to the oxygen sensor set points that are not within 72 hours prior to the diagnostic emission check, returning to a more frequent diagnostic emission check schedule is not required if the engine is in compliance with the applicable emission limits prior to and after the set point adjustments.
 - (II) For diesel engines and other lean-burn engines that operate at a RECLAIM or former RECLAIM facility or have a NO_x CEMS, and that are subject to a CO limit more stringent than the 2000 ppmvd limit

- (f) of Tables II or III, a CO diagnostic emission check shall be performed at least quarterly, or every 2,000 engine operating hours, whichever occurs later.
- (III) For diesel engines and other lean-burn engines that operate at a RECLAIM or former RECLAIM facility or have a NO_x CEMS, and that are not subject to a CO limit more stringent than the 2000 ppmvd limit of Tables II or III, diagnostic emission checks are not required.
- (IV) No engine or control system maintenance or tuning may be conducted within 72 hours prior to the diagnostic emission check, unless it is an unscheduled, required repair.
- (V) The portable analyzer shall be calibrated, maintained and operated in accordance with the manufacturer's specifications and recommendations and the Protocol for the Periodic Monitoring of Nitrogen Oxides, Carbon Monoxide, and Oxygen from Stationary Engines Subject to South Coast Air Quality Management District Rule 1110.2, approved on February 1, 2008, or subsequent protocol approved by EPA and the Executive Officer.
- (iii) Requirements for responding to, diagnosing and correcting breakdowns, faults, malfunctions, alarms, diagnostic emission checks finding emissions in excess of rule or permit limits, and parameters out-of-range.
 - (I) For any diagnostic emission check or breakdown that results in emissions in excess of those allowed by this rule or a permit condition, the operator shall correct the problem as soon as possible and demonstrate compliance with another diagnostic emission check, or shut down an engine by the end of an operating cycle, or within 24 hours from the time the operator knew of the breakdown or excess emissions, or reasonably should have known,

- (f) whichever is sooner.
- (II) For excess emissions due to breakdowns that result in NO_x or CO emissions greater than the concentrations specified in Table VIII, the operator shall not be considered in violation of this rule if the operator demonstrates the all of the following: (1) compliance with subclause (f)(1)(D)(iii)(I), (2) compliance with the reporting requirements of subparagraph (f)(1)(H), and (3) the engine with excess emissions has no more than three incidences of breakdowns with emissions exceeding Table VIII limits in the calendar quarter.

TABLE VIII EXCESS EMISSION CONCENTRATION THRESHOLDS FOR BREAKDOWNS		
	NO _x (ppmvd) ¹	CO (ppmvd) ¹
Lean-Burn Engines	45	250
Rich-Burn Engines	150	2000
Biogas Engines ²	185	2000

¹ Corrected to 15% oxygen.

² Effective up to the time of compliance with the limits specified in Table III-B, after which the thresholds revert to the applicable lean or rich-burn engine limits.

- (III) Any emission check conducted by South Coast AQMD staff that finds excess emissions will be treated as a violation.
- (IV) For other problems, such as parameters out-of-range, an operator shall correct the problem and demonstrate compliance with another diagnostic emission check within 48 hours of the operator first knowing of the problem.
- (iv) If an engine has a NO_x CEMS and does not have a CO CEMS, it is subject to this subparagraph (f)(1)(D) as it

(f) pertains to CO only.

(E) Operating Log

Maintain a monthly engine operating log that includes:

- (i) Total hours of operation;
- (ii) Type of liquid and/or type of gaseous fuel;
- (iii) Fuel consumption (cubic feet of gas and gallons of liquid); and
- (iv) Cumulative hours of operation since the last source test required in subparagraph (f)(1)(C).

Facilities subject to Regulation XX may maintain a quarterly log for engines that are designated as a process unit on the facility permit until such time that the facility becomes a former RECLAIM facility. The facility shall maintain a monthly engine log starting in the month that it has become a former RECLAIM facility.

(F) New Non-Emergency Electrical Generating Engines

Operators of engines subject to the requirements of subparagraph (d)(1)(L) shall also meet the following requirements.

- (i) The engine generator shall be monitored with a calibrated electric meter that measures the net electrical output of the engine generator system, which is the difference between the electrical output of the generator and the electricity consumed by the auxiliary equipment necessary to operate the engine generator.
- (ii) For engines monitored with a CEMS, the emissions of the monitored pollutants in ppmvd corrected to 15% O₂, lbs/hr, and lbs/MW_e-hr and the net MW_e-hrs produced shall be calculated and recorded for the four 15-minute periods of each hour of operation. The mass emissions of NO_x shall be calculated based on the measured fuel flow and one of the F factor methods of 40 CFR Part 60, Appendix A, Method 19, or other method approved by the Executive Officer. Mass emissions of CO shall be calculated in the same manner as NO_x, except that the ppmvd CO shall be converted to lb/scf using a conversion factor of 0.727×10^{-7} .

- (f)
- (iii) For NO_x and CO emissions from engines not monitored with a CEMS and VOC emissions from all engines, the emissions of NO_x, CO and VOC in lbs/MW_e-hr shall be calculated and recorded whenever the pollutant is measured by a source test or diagnostic emission check. Mass emissions of NO_x and CO shall be calculated in the same manner as the previous clause. Mass emissions of VOC shall be calculated in the same manner, except that the ppmvd VOC as carbon shall be converted to lb/scf using a conversion factor of 0.415×10^{-7} .
 - (iv) For engines generating combined heat and power that rely on the EEF to comply with Table IV emission standards, the daily and annual useful heat recovered (MW_{th}-hrs), net electrical energy generated (MW_e-hrs) and EEF shall be monitored and recorded.
 - (v) Other methods of calculating mass emissions than those specified, such as by direct measurement of exhaust volume, may be used if approved by the Executive Officer. All monitoring, calculation, and recordkeeping procedures must be approved by the Executive Officer.
 - (vi) Operators of combined heat and power engines shall submit to the Executive Officer the reports of the following information within 15 days of the end of the first year of operation, and thereafter within 15 days of the end of each calendar year: the annual net electrical energy generated (MW_e-hrs); the annual useful heat recovered (MW_{th}-hrs), the annual EEF calculated in accordance with clause (d)(1)(L)(ii); and the maximum annual EEF allowed by the operating permit. If the actual annual EEF exceeds the allowed EEF, the report shall also include the time periods and emissions for all instances where emissions exceeded any emission standard in Table IV.

(G) Portable Analyzer Operator Training

The portable analyzer tests required by the I&M Plan requirements of subparagraph (f)(1)(D) shall only be conducted by a person who

- (f) has completed an appropriate South Coast AQMD-approved training program in the operation of portable analyzers and has received a certification issued by the District.

(H) Reporting Requirements

- (i) The operator shall report to the Executive Officer, by telephone (1-800-CUT-SMOG or 1-800-288-7664) or other South Coast AQMD-approved method, any breakdown resulting in emissions in excess of rule or permit emission limits within one hour of such noncompliance or within one hour of the time the operator knew or reasonably should have known of its occurrence. Such report shall identify the time, specific location, equipment involved, responsible party to contact for further information, and to the extent known, the causes of the noncompliance, and the estimated time for repairs. In the case of emergencies that prevent a person from reporting all required information within the one-hour limit, the Executive Officer may extend the time for the reporting of required information provided the operator has notified the Executive Officer of the noncompliance within the one-hour limit.
- (ii) Within seven calendar days after the reported breakdown has been corrected, but no later than thirty calendar days from the initial date of the breakdown, unless an extension has been approved in writing by the Executive Officer, the operator shall submit a written breakdown report to the Executive Officer which includes:
 - (I) An identification of the equipment involved in causing, or suspected of having caused, or having been affected by the breakdown;
 - (II) The duration of the breakdown;
 - (III) The date of correction and information demonstrating that compliance is achieved;
 - (IV) An identification of the types of excess emissions, if any, resulting from the breakdown;
 - (V) A quantification of the excess emissions, if any, resulting from the breakdown and the basis used to

- (f) quantify the emissions;
 - (VI) Information substantiating whether the breakdown resulted from operator error, neglect or improper operation or maintenance procedures;
 - (VII) Information substantiating that steps were immediately taken to correct the condition causing the breakdown, and to minimize the emissions, if any, resulting from the breakdown;
 - (VIII) A description of the corrective measures undertaken and/or to be undertaken to avoid such a breakdown in the future; and
 - (IX) Pictures of any equipment which failed, if available.
- (iii) Within 15 days of the end of each calendar quarter, the operator shall submit to the Executive Officer a report that lists each occurrence of a breakdown, fault, malfunction, alarm, engine or control system operating parameter out of the acceptable range established by an I&M plan or permit condition, or a diagnostic emission check that finds excess emissions. Such report shall be in a South Coast AQMD-approved format, and for each incident shall identify the time of the incident, the time the operator learned of the incident, specific location, equipment involved, responsible party to contact for further information, to the extent known the causes of the event, the time and description of corrective actions, including shutting an engine down, and the results of all portable analyzer NO_x and CO emissions checks done before or after the corrective actions. The operator shall also report if no incidents occurred.

(2) Portable engines:

The operator of any portable engine shall maintain a monthly engine operating log that includes:

- (i) Total hours of operation; or
- (ii) Type of liquid and/or type of gaseous fuel; and
- (iii) Fuel consumption (cubic feet of gas and gallons of liquid).

Facilities subject to Regulation XX may maintain a quarterly log for engines that are designated as a process unit on the facility permit until

- (f) such time that the facility becomes a former RECLAIM facility. The facility shall maintain a monthly engine log starting in the month that it has become a former RECLAIM facility.
- (3) Recordkeeping for All Engines
All data, logs, test reports and other information required by this rule shall be maintained for at least five years and made available for inspection by the Executive Officer.
- (g) Test Methods
Testing to verify compliance with the applicable requirements shall be conducted in accordance with the test methods specified in Table IX, or any test methods approved by CARB and EPA, and authorized by the Executive Officer.

TABLE IX TESTING METHODS	
Pollutant	Method
NO _x	South Coast Air Quality Management District Method 100.1
CO	South Coast Air Quality Management District Method 100.1
VOC	South Coast Air Quality Management District Method 25.1* or Method 25.3*

* Excluding ethane and methane

A violation of any standard of this rule established by any of the specified test methods, or any test methods approved by the CARB or EPA, and authorized by the Executive Officer, shall constitute a violation of this rule.

- (h) Alternate Compliance Option
- (1) In lieu of complying with the applicable emission limits by the effective date specified in Table III-B or subparagraph (d)(1)(F), owners or operators of biogas-fired units may elect to defer compliance in quarterly increments up to one additional year, provided the owner or operator:
- (A) Submits an alternate compliance plan and pays a Compliance Flexibility Fee, as provided for in paragraph (h)(2), to the Executive Officer at least 60 days prior to the applicable compliance date in either Table III-B or subparagraph (d)(1)(F) for qualified biogas technology demonstration project engines, and

- (h) (B) Maintains on-site a copy of verification of Compliance Flexibility Fee payment and South Coast AQMD approval of the alternate compliance plan that shall be made available upon request to South Coast AQMD staff.

- (2) Plan Submittal

The alternate compliance plan submitted pursuant to paragraph (h)(1) shall include:

- (A) A completed South Coast AQMD Form 400A with company name, South Coast AQMD Facility ID, identification that application is for a compliance plan (Section 7a of form), and identification that request is for Rule 1110.2 Compliance Flexibility Fee option (Section 9 of form);
- (B) Attached documentation of unit permit ID, unit rated brake horsepower (bhp), and fee calculation;
- (C) Filing Fee payment; and
- (D) Compliance Flexibility Fee payment as calculated by the following equation:

$$\text{CFF} = \text{bhp} \times \text{R} \times \text{Q}$$

Where,

CFF = Compliance Flexibility Fee, \$

bhp = rated brake horsepower of unit

R = Fee Rate = \$11.75 per brake horsepower per quarter

Q = Number of quarters (up to four)

- (3) Usage of Compliance Flexibility Fee funds

The funds collected from the Compliance Flexibility Fee will be applied to South Coast AQMD NO_x reduction programs pursuant to protocols approved under South Coast AQMD rules.

- (i) Exemptions

- (1) The provisions of subdivision (d) shall not apply to:

- (A) All orchard wind machines powered by an internal combustion engine.
- (B) Emergency standby engines, engines used for fire-fighting and flood control, and any other emergency engines approved by the Executive Officer, which have permit conditions that limit

- (i) operation to 200 hours or less per year as determined by an elapsed operating time meter, and agricultural emergency standby engines that are exempt from a South Coast AQMD permit and operate 200 hours or less per year as determined by an elapsed operating time meter.
- (C) Laboratory engines used in research and testing purposes.
- (D) Engines operated for purposes of performance verification and testing of engines.
- (E) Auxiliary engines used to power other engines or gas turbines during start-ups.
- (F) Portable engines that are registered under the state registration program pursuant to Title 13, Article 5 of the CCR.
- (G) Nonroad engines, with the exception that subparagraph (d)(2)(A) shall apply to portable generators.
- (H) Engines operating on San Clemente Island.
- (I) Agricultural stationary engines provided that:
 - (i) The operator submits documentation to the Executive Officer by the applicable date in Table V when permit applications are due that the applicable electric utility has rejected an application for an electrical line extension to the location of the engines, or the Executive Officer determines that the operator does not qualify, due to no fault of the operator, for funding authorized by California Health and Safety Code Section 44229; and
 - (ii) The operator replaces the engines, in accordance with the compliance schedule of Table X, with engines certified by CARB to meet the Tier 4 emission standards of 40 CFR Part 1039 Section 1039.101, Table 1. These Tier 4 replacement engines shall be considered to comply with Best Available Control Technology; and
 - (iii) The operator does not operate the Tier 4 engines in a manner that exceeds the not-to-exceed standards of 40 CFR Part 1039 Section 1039.101(e), as determined by the test methods of subdivision (g) of this rule.

(i)

TABLE X COMPLIANCE SCHEDULE FOR INSTALLATION OF NEW TIER 4 STATIONARY AGRICULTURAL ENGINES	
Action Required	Due Date
Submit to the Executive Officer applications for permits to construct engine modifications, control equipment, or replacement engines	March 1, 2013
Initiate construction of engine modifications, control equipment, or replacement engines	September 30, 2013, or 30 days after the permit to construct is issued, whichever is later
Complete construction and comply with applicable requirements	January 1, 2014, or 60 days after the permit to construct is issued, whichever is later
Complete initial source testing	March 1, 2014, or 120 days after the permit to construct is issued, whichever is later

- (J) An engine start-up, until sufficient operating temperatures are reached for proper operation of the emission control equipment or for the tuning of the engine and/or emission control equipment, and an engine shutdown period. The periods shall not exceed 30 minutes, unless the Executive Officer approves in writing a longer period not exceeding two hours for an engine and makes it a condition of the engine permit.
- (K) An engine start-up, after an engine overhaul or major repair requiring removal of a cylinder head or for the installation or the replacement of catalytic emission control equipment, for a period not to exceed four operating hours.
- (L) The initial commissioning of a new engine for a period specified by permit conditions, provided the operator takes measures to reduce emissions and the duration of the commissioning to the extent possible. The commissioning period shall not exceed 150 operating hours.

- (i) (M) An engine used exclusively for electrical generation at remote two-way radio transmission towers where no utility, electricity, or natural gas is available within a ½ mile radius, has a manufacturer's rating of 100 bhp or less, and is fired exclusively on diesel #2, compressed natural gas, or liquefied petroleum gas.
- (N) Any engine at a RECLAIM or former RECLAIM facility that is subject to a NOx emission limit in a different rule for an industry-specific category defined in Rule 1100 – Implementation Schedule for NOx facilities.
- (O) An engine operated in either the Southern California Coastal Waters or Outer Continental Shelf Waters provided:
 - (i) The engine is used to power a crane;
 - (ii) The engine is certified by CARB to meet the Tier 4 – Final emission standards of 40 CFR Part 1039 Section 1039.101 Table 1;
 - (iii) The engine is operated per the specifications of the engine manufacturer; and
 - (iv) The operator submits an I&M Plan to the Executive Officer for approval and implementation, pursuant to the requirements of subparagraph (f)(1)(D).
- (2) The facility operator of MM PRIMA DESHECHA ENERGY, LLC, or any of its successors, shall not be required to meet the emissions requirements specified in Table III-B if they submit a detailed retirement plan that is approved by the Executive Officer for the permanent shutdown of all equipment subject to Rule 1110.2 by October 1, 2022. The plan shall describe in detail the steps and schedule that will be taken to remove the equipment or render the equipment permanently inoperable by October 1, 2022 and shall require the surrendering of the permits for the equipment by that date. The plan shall be submitted before July 1, 2016 and include:
 - (A) South Coast AQMD Form 400A with company name, South Coast AQMD Facility ID, and permit number(s) for the subject equipment; and
 - (B) Filing Fee payment pursuant to Rule 306.The Executive Officer shall act on the plan before January 1, 2017.

- (i) (3) The provisions of this rule shall not apply to units located at landfills or publicly owned treatment works that are subject to a NO_x emission limit in a Regulation XI rule adopted or amended after November 1, 2019.

ATTACHMENT 1

An I&M Plan submitted to the Executive Officer for approval and implementation, pursuant to the requirements of paragraphs (e)(4) and (e)(6), and subparagraph (f)(1)(D) of the rule, shall include:

- A. Identification of engine and control equipment operating parameters necessary to maintain pollutant concentrations within the rule and permit limits. This shall include, but not be limited to:
 - 1. Procedures for using a portable NO_x, CO and oxygen analyzer to establish the set points of the air-to-fuel ratio controller (AFRC) at 25%, 60% and 95% load (or fuel flow rate), $\pm 5\%$, or the minimum, midpoint and maximum loads that actually occur during normal operation, $\pm 5\%$, or at any one load within the $\pm 10\%$ range that an engine permit is limited to in accordance with clause (f)(1)(C)(ii) of the rule;
 - 2. Procedures for verifying that the AFRC is controlling the engine to the set point during the daily monitoring required by subdivision D of this attachment;
 - 3. Procedures for reestablishing all AFRC set points with a portable NO_x, CO and oxygen analyzer whenever a set point must be readjusted, within 24 hours of an oxygen sensor replacement, and, for rich-burn engines with three way catalysts, between 100 and 150 engine operating hours after an oxygen sensor replacement;
 - 4. For engines with catalysts, the maximum allowed exhaust temperature at the catalyst inlet, based on catalyst manufacturer specifications;
 - 5. For lean-burn engines with selective catalytic control devices, the minimum exhaust temperature at the catalyst inlet required for reactant flow (ammonia or urea), and procedures for using a portable NO_x and oxygen analyzer to establish the acceptable range of reactant flow rate, as a function of load.

Parameter monitoring is not required for diesel engines without exhaust gas recirculation and catalytic exhaust control devices.

- B. Procedures for alerting the operator to emission control malfunctions. Engine control systems, such as air-to-fuel ratio controllers, shall have a malfunction indicator light and audible alarm.
- C. Procedures for diagnostic emission checks conducted by a portable NO_x, CO, and oxygen analyzer per the requirements of clause (f)(1)(D)(ii) of the rule.
- D. Procedures for at least daily monitoring, inspection and recordkeeping of:

1. engine load or fuel flow rate;
2. the set points, maximums and acceptable ranges of the parameters identified by subdivision A of this attachment, and the actual values of the same parameters;
3. the engine elapsed time meter operating hours;
4. the operating hours since the last diagnostic emission check required by clause (f)(1)(D)(ii) of the rule;
5. for rich-burn engines with three-way catalysts, the difference of the exhaust temperatures (ΔT) at the inlet and outlet of the catalyst (changes in the ΔT can indicate changes in the effectiveness of the catalyst);
6. engine control system and AFRC system faults or alarms that affect emissions.

The daily monitoring and recordkeeping may be done in person by the operator, or by remote monitoring.

- E. Procedures for responding to, diagnosing and correcting breakdowns, faults, malfunctions, alarms, diagnostic emission checks finding emissions in excess of rule or permit limits, and parameters out-of-range, per the requirements of clause (f)(1)(D)(iii) of the rule.
- F. Procedures and schedules for preventive and corrective maintenance.
- G. Procedures for reporting noncompliance to the Executive Officer in accordance with subparagraph (f)(1)(H) of the rule.
- H. Procedures and format for the recordkeeping of monitoring and other actions required by the plan.



Stationary Reciprocating Internal Combustion Engines

Updated Information on NO_x Emissions and Control Techniques

Stationary Reciprocating Internal Combustion Engines
Updated Information on NO_x Emissions and Control Techniques

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Office of Air Quality Planning and Standards
Air Quality Policy Division
Research Triangle Park, NC

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1.0 INTRODUCTION

1.1 PURPOSE OF THIS DOCUMENT

The purpose of this document is to update portions of *Alternative Control Techniques Document—NO_x Emissions from Stationary Reciprocating Internal Combustion Engines* (the 1993 ACT document).¹ This update will provide more recent data on emission control technologies and control costs.

This report focuses on the natural gas transmission and storage industry because this is a large segment of stationary reciprocating internal combustion (IC) engine users. In addition, the report focuses on low emission combustion (LEC) control technology because developments in the technology and costs make an update especially necessary.

This document does not replace the 1993 ACT document, but only updates certain portions. The reader should refer to the 1993 ACT document for additional information on the types of IC engines, the mechanisms of the formation of nitrogen oxides (NO_x) in IC engines, the full range of control alternatives and the technical details of each, and the costs and cost effectiveness of controls.

1.2 METHODS

Data were collected for this report primarily through site visits at facilities that operate IC engines equipped with controls for NO_x emissions; contacts with engine manufacturers, control technology vendors, and regulatory agencies; and a literature search. Additional information was obtained through seeking out useful sites on the Internet.

1.3 ORGANIZATION

Chapter 2 presents a summary of the findings of this study. Chapter 3 addresses uncontrolled emissions from selected IC engine types. Chapter 4 presents an update on selected NO_x control technologies. Chapter 5 presents a limited update on control costs and cost effectiveness.

1.4 REFERENCE FOR CHAPTER 1

1. *Alternative Control Techniques Document–NO_x Emissions from Stationary Reciprocating Internal Combustion Engines*. U. S. Environmental Protection Agency, Research Triangle Park, NC. Publication No. EPA-453/R-93-032. July 1993. 315pp.
<http://www.epa.gov/ttnecatc1/products.html>.

2.0 SUMMARY

This report primarily addresses nitrogen oxides (NO_x) emissions and cost data from lean-burn, spark-ignited (SI) stationary reciprocating internal combustion (IC) engines equipped with low-emission combustion (LEC) technology. This chapter presents a summary of updated information on these engines. This information is presented in greater depth in subsequent chapters, along with less extensive information on other selected types of IC engines and NO_x control technologies. Section 2.1 includes a summary of performance test data on NO_x emissions from lean-burn SI engines controlled with LEC technology. Section 2.2 presents a summary of updated control costs for these engines.

Throughout this document, NO_x emissions are expressed as grams per brake horsepower hour (g/bhp-hr) and/or parts per million by volume (ppmv). Unless otherwise stated, all concentrations given in units of ppmv are on a dry basis and corrected to 15 percent oxygen. The primary unit is g/bhp-hr because it expresses emissions on a comparable basis across all IC engine types and models, and because it is the standard practice.

In preparing this report, the following conversion factors were used as necessary:

- Uncontrolled rich-burn SI engines and rich-burn engines controlled with nonselective catalytic reduction (NSCR): 67 ppmv = 1 g/bhp-hr
- Uncontrolled lean-burn engines, lean-burn engines controlled with selective catalytic reduction (SCR), and rich-burn engines controlled with prestratified charge™ (PSC) technology: 73 ppmv = 1 g/bhp-hr
- Lean-burn engines controlled with low emission combustion technology: 75 ppmv = 1 g/bhp-hr

For example, when emission test results were reported only in ppmv, these factors were used to convert the results to g/bhp-hr. These conversion factors are consistent with those used in *Alternative Control Techniques Document—NO_x Emissions from Stationary Reciprocating Internal Combustion Engines* (the 1993 ACT document).¹

The NO_x emission unit of pounds per million British thermal units input (lb/MMBtu) is not used in this report because it is less frequently used in conjunction with IC engines. As a

result, a comparison of IC engine NO_x emissions with emission from other types of fuel-burning equipment cannot always be readily made. However, it should be noted that uncontrolled IC engine emissions in terms of heat input can be over an order of magnitude higher than emissions from turbines or boilers. Well controlled IC engines often emit NO_x at higher levels than uncontrolled gas turbines and boilers.

2.1 CONTROLLED NO_x EMISSIONS FROM LEC-EQUIPPED ENGINES

Table 2-1 presents LEC emissions data from several different sources. In a May 2000 memo, the EPA summarized data from 269 emissions tests on a variety of engines makes, models, and sizes. In addition to the data from the EPA memo, Table 2-1 presents data from 476 different NO_x emissions tests for 58 engines with LEC technology. Other sources of data for the table include performance test data bases from the San Diego, Santa Barbara, and Ventura County (California) Air Pollution Control Districts, test data summaries from Southern California Gas Company and Pacific Gas and Electric Company, and a Gas Research Institute (GRI) report prepared by Arthur D. Little, Inc. Note that the EPA memo also includes data from earlier versions of the Ventura and Santa Barbara County data bases.

Table 2-1 shows that the emissions ranged from 0.1 to 4.8 g/bhp-hr. Nearly 97 percent of these tests (460) found emissions less than or equal to 2 g/bhp-hr. Almost 75 percent (354) of the tests found emissions less than or equal to 1 g/bhp-hr, and 25 percent (120) found emissions of less than or equal to 0.5 g/bhp-hr. Only two tests found emissions greater than or equal to 4 g/bhp-hr.

Chapter 4 contains a more detailed update on NO_x control technologies, including LEC, selective catalytic reduction (SCR), Prestratified Charge™ (PSC), and nonselective catalytic reduction (NSCR).

2.2 CONTROL COSTS FOR LEC-EQUIPPED ENGINES

The results of the cost analysis in 1990 and 1997 dollars are summarized in Tables 2-2a and 2-2b, respectively. The tables present total capital investment and annual costs of LEC controls for eight engine sizes ranging from 80 to 8,000 bhp. In addition, the tables include the NO_x emission reductions and cost effectiveness on an annual basis and for the ozone season (May through September). The tables show that capital and annual costs increase with engine size. For example, Table 2-2b (1997 dollars) shows that capital and annual costs for an 80 bhp engine would be \$231,000 and \$59,100, respectively, whereas for an 8,000 bhp engine, these costs would be \$760,000 and \$175,000. On the other hand, the cost effectiveness per ton of NO_x reduced varies inversely with engine size. Table 2-2b (1997 dollars) shows that cost effectiveness varies from \$6,470 annually and \$15,500 for the ozone season for an 80 bhp engine, down to \$192 annually and \$460 for the ozone season for an 8,000 bhp engine.

As explained in greater detail in Chapter 5, we obtained information on LEC costs from several sources. The cost and cost effectiveness projections presented in Tables 2-2a and 2-2b

TABLE 2-1. NO_x EMISSIONS DATA FROM ENGINES WITH LEC CONTROL TECHNOLOGY

Source	No. of tests	No. of engines	No. of models	Minimum emissions (g/bhp-hr)	Maximum emissions (g/bhp-hr)	Average emissions (g/bhp-hr)	Tests ≤3 g per bhp-hr		Tests ≤2 g per bhp-hr		Tests ≤1 g per bhp-hr		Tests ≤0.5 g per bhp-hr		Tests ≥4 g per bhp-hr	
							No.	%	No.	%	No.	%	No.	%	No.	%
EPA Memo ²	269	49	≥22	0.1	6.0	NA	266	99%	258	96%	192	71%	NA	NA	1	<1%
Ventura County ^{3 a}	320	23	8	0.1	4.0	0.7	319	>99%	318	99%	275	86%	102	32%	1	<1%
Santa Barbara County ^{4 a}	12	3	3	0.1	0.7	0.5	12	100%	12	100%	12	100%	8	67%	0	0%
San Diego County ⁵	121	13	5	0.3	4.8	1.1	120	99%	108	89%	52	43%	7	6%	1	1%
So. California Gas Company ⁶	7	7	1	0.8	1.5	1.1	7	100%	7	100%	5	71%	0	0%	0	0%
So. California Gas Company ⁷	3	3	1	0.5	0.6	0.6	3	100%	3	100%	2	67%	1	33%	0	0%
So. California Gas Company ⁸	1	1	1			0.6	1	100%	1	100%	1	100%	0	0%	0	0%
So. California Gas Company ⁹	7	5	1	0.4	0.7	0.6	7	100%	7	100%	7	100%	2	29%	0	0%
Pacific Gas and Electric ¹⁰	2	2	1	1.0	1.3	1.2	2	100%	2	100%	1	50%	0	0%	0	0%
GRI Report ¹¹	3	1	1	1.4	2.4	1.9	3	100%	2	67%	1	33%	0	0%	0	0%
Summary ^b	476	58	15	0.1	4.8	0.8	474	>99%	460	97%	356	75%	120	25%	2	<1%

NA = Not Available

^aVentura County and Santa Barbara County data are more recent, more extensive versions of emission test data bases included in the EPA memo (see Section 4.1.3.2).

^bThe summary calculation does not include data from the EPA memo in order to avoid double counting Ventura County and Santa Barbara County data that appear in both data sets. Percentages in this row were calculated relative to a total of 476 tests.

TABLE 2-2a. COSTS AND COST EFFECTIVENESS OF LEC CONTROLS IN 1990 \$'s

Engine size, bhp	Total capital investment	Annual cost	NO _x reduction, tons		Cost effectiveness, \$/ton NO _x	
			Annual	O ₃ season	Annual	O ₃ season
80	\$214,000	\$55,000	9	4	\$6,020	\$14,400
240	\$224,000	\$57,000	27	11	\$2,080	\$4,990
500	\$240,000	\$60,500	57	24	\$1,060	\$2,540
1,000	\$271,000	\$67,100	114	48	\$590	\$1,410
2,000	\$333,000	\$80,400	228	95	\$350	\$840
4,000	\$456,000	\$107,000	457	190	\$240	\$560
6,000	\$580,000	\$134,000	685	285	\$170	\$470
8,000	\$703,000	\$161,000	914	381	\$180	\$420

TABLE 2-2b. COSTS AND COST EFFECTIVENESS OF LEC CONTROLS IN 1997 \$'s

Engine size, bhp	Total capital investment	Annual cost	NO _x reduction, tons		Cost effectiveness, \$/ton NO _x	
			Annual	O ₃ season	Annual	O ₃ season
80	\$231,000	\$59,100	9	4	\$6,470	\$15,500
240	\$242,000	\$61,400	27	11	\$2,240	\$5,380
500	\$259,000	\$65,200	57	24	\$1,140	\$2,740
1,000	\$293,000	\$72,400	114	48	\$630	\$1,520
2,000	\$359,000	\$86,900	228	95	\$380	\$910
4,000	\$493,000	\$116,000	457	190	\$250	\$610
6,000	\$627,000	\$146,000	685	285	\$210	\$510
8,000	\$760,000	\$175,000	914	381	\$190	\$460

are based on new information on actual costs for several LEC retrofits obtained from one engine manufacturer and one third-party LEC vendor. Other inputs include uncontrolled NO_x emissions of 16.8 g/bhp-hr, controlled emissions of 2.0 g/bhp-hr, and capacity utilization of 7,000 operating hours per year (prorated for the 5 months of the ozone season). In most respects, the analysis was conducted according to the methodology of the 1993 ACT document, which, in turn, was based on the *OAQPS Control Cost Manual*. For additional detail, refer to Section 5.1.

No other cost analyses were carried out for this report. However, some cost information was obtained during this study on modern SCR systems that use urea as the reducing agent for control of NO_x emissions from lean-burn SI engines and diesel engines. See Section 5.2 of Chapter 5 for that information.

2.3 REFERENCES FOR CHAPTER 2

1. *Alternative Control Techniques Document–NO_x Emissions from Stationary Reciprocating Internal Combustion Engines*. U. S. Environmental Protection Agency, Research Triangle Park, NC. Publication No. EPA-453/R-93-032. July 1993. 315pp. <http://www.epa.gov/ttnca1/products.html>.
2. Memo from D. Sanders, EPA, to D. Grano, EPA, and Docket No. A-98-12. Performance of Low Emission Combustion. May 19, 2000.
3. Memo from S. Edgerton, EC/R Inc., to Project File. Analysis of Ventura County APCD Test Data–Low Emission Combustion. July 28, 2000.
4. Memo from S. Edgerton, EC/R Inc., to Project File. Analysis of Santa Barbara County APCD Test Data–Low Emission Combustion. July 28, 2000.
5. Memo from S. Edgerton, EC/R Inc., to Project File. Analysis of San Diego County APCD Test Data–Low Emission Combustion. July 28, 2000.
6. EC/R Incorporated. Final Site Visit Reports for Southern California Gas Company Facilities, Attachment 5. Prepared for Ozone Policy and Strategies Group, U. S. Environmental Protection Agency, Research Triangle Park, NC. June 26, 2000. 12pp.
7. Southern California Gas Company. Facsimile from G. Arney to S. Edgerton, EC/R Incorporated. Information on Aliso Canyon Station. Southern California Gas Company, Aliso Canyon, CA. December 16, 1999. 26pp.
8. Southern California Gas Company. Facsimile from G. Arney to S. Edgerton, EC/R Incorporated. Information on Goleta Station. Southern California Gas Company, Goleta Station, CA. December 16, 1999. 24pp.
9. Southern California Gas Company. Facsimile from G. Arney to S. Edgerton, EC/R Incorporated. Information on Honor Rancho Station. Southern California Gas Company, Honor Rancho Station, CA. December 16, 1999. 16pp.
10. Pacific Gas and Electric Company. Letter and attachments from C. Burke to W. Neuffer, U. S. EPA. Information on Hinkley Compressor Station Units K-11 and K-12. Pacific Gas and Electric Company. February 3, 2000. 8pp.
11. GRI-98/0117. *NO_x Control for Two-Cycle Pipeline Reciprocating Engines*. Prepared by Arthur D. Little, Inc., for the Gas Research Institute. December 1998.

3.0 UNCONTROLLED NO_x EMISSIONS

This chapter presents information on uncontrolled emissions of nitrogen oxides (NO_x) from stationary reciprocating internal combustion (IC) engines that has been generated since EPA published its *Alternative Control Techniques Document–NO_x Emissions from Stationary Reciprocating Internal Combustion Engines* (the 1993 ACT document).¹ This chapter updates the information in the 1993 ACT document, but is not intended to replace it. For example, this chapter does not discuss NO_x formation mechanisms; the reader should refer to the 1993 ACT document for a discussion of NO_x formation.

For purposes of this report, “uncontrolled emissions” are defined as the NO_x emission level prior to any actions taken to reduce emissions, such as adjusting the engine’s operating parameters, retrofitting an engine for combustion modification, installing an add-on control device, or redesigning new engines for improved emissions performance. Thus, engines that include low-emission combustion (LEC) technology as original equipment are considered controlled, rather than uncontrolled. To the extent possible, these engines will be excluded from average uncontrolled emissions values. In contrast, engine technologies that have been incorporated for purposes other than emission reduction that, nevertheless, reduce NO_x emissions (notably turbocharging and intercooling) are not necessarily considered control technologies, unless undertaken as part of a project to reduce emissions.

This chapter addresses lean-burn, spark-ignited (SI) engines fired on pipeline-quality natural gas (Section 3.1) and rich-burn SI engines, also fired on pipeline-quality natural gas (Section 3.2). No additional data on diesel-fueled, compression-ignition (CI) engines and dual-fuel CI engines, which use diesel fuel to initiate combustion of natural gas, were collected for this report. The CI engine types are not addressed in this chapter. Section 3.3 provides the references for this entire chapter.

3.1 LEAN-BURN SI ENGINES

This section presents and discusses information on uncontrolled NO_x emissions from lean-burn SI engines. Section 3.1.1 presents the information, and Section 3.1.2 provides a discussion of the information and presents conclusions.

3.1.1 Information on Uncontrolled NO_x Emissions from Lean-Burn SI Engines

Some information sources reviewed for this report include NO_x emission factors based on aggregated test data or contain actual test results. These information sources are described briefly in the paragraphs that follow.

A 1994 Gas Research Institute (GRI) report includes separate NO_x emission levels for 2-stroke (12.5 grams per brake horsepower-hour [g/bhp-hr]) and 4-stroke (13.2 g/bhp-hr) lean-burn natural gas prime movers. (These are lean-burn SI engines used in natural gas compression, transmission, and storage service, which represents a major segment of the population of this type of engine.) The emission levels included in the report are based on an extensive data base of emission test results, although the number of lean-burn engine tests is not stated. The reported emission levels are weighted averages, weighted based on the natural gas prime mover population (i.e., the number of each engine model in prime mover service according to 1989 data) and on horsepower. Test results for 2-stroke engines ranged from 2 g/bhp-hr to 29 g/bhp-hr. For 4-stroke engines, the results ranged from 1 g/bhp-hr to 25 g/bhp-hr.

This report notes that the higher end of the range (25 to 29 g/bhp-hr) reflects older, uncontrolled engines. Engines equipped with turbochargers and intercoolers as original design features (“pure turbocharged” engines) typically emit NO_x in the 7 to 15 g/bhp-hr range. The lower end of the range often reflects the newer lean-burn engines that are included in the inventory, which achieve very low NO_x emissions (1 to 2 g/bhp-hr) through the use of higher excess air and advanced ignition technology (i.e., engines classified as controlled using LEC technology for purposes of this report—see Section 4.1.1). The GRI report also notes that LEC technology is available for retrofit, although it does not state whether any retrofitted engines are included in the inventory of test results.² Thus, the average emission levels presented in this GRI report were calculated including some engines considered controlled for purposes of this report. The number of such engines included and their effect on the reported average is not known.

The EPA’s *Compilation of Air Pollutant Emission Factors* (AP-42) current Section 3.2 on natural gas prime movers (dated October 1996) characterizes uncontrolled NO_x emissions as 10.9 g/bhp-hr for 2-stroke engines and as 11.8 g/bhp-hr for 4-stroke engines, based on emission test data. This document includes many of the same test data references as the GRI report discussed above, including compilations of test data prepared for the natural gas industry that contain the bulk of the test results considered.³ It is not clear why these emission factors are lower than the GRI report’s, although it likely relates to the averaging methodology. The AP-42 section indicates that these values represent uncontrolled emissions, and the section also contains NO_x emission factors for controlled lean-burn engines (including factors for two manufacturers’ LEC-equipped engines—see Section 4.1.3). However, based on the large overlap with the GRI data, it appears likely that the “uncontrolled” data include test results from newer lean-burn engines that would be considered controlled (i.e., LEC-equipped) for purposes of this report.

The 1997 draft revision for AP-42 Section 3.2 indicates uncontrolled NO_x emissions of 12.2 g/bhp-hr for 2-stroke lean-burn engines and 15.0 g/bhp-hr for 4-stroke lean-burn engines, based on emission test data (38 tests for 2-stroke engines and 18 tests for 4-stroke engines). The

draft also includes emission factors for 2-stroke and 4-stroke “clean-burn” engines, referring to these engines as separate “engine families,” distinct from other lean-burn engines.^{4,5} “CleanBurn” is a registered trademark of Cooper Energy Services, denoting that company’s system of precombustion chambers coupled with a high-efficiency turbocharger. This system is included in the definition of LEC technology used in this document.

During comment on the 1997 draft AP-42 section, other companies noted that they also offer similar technology (i.e., LEC), but refer to these engines simply as “lean-burn engines.” Thus, some engines equipped with LEC technology were believed to have been included in the uncontrolled, lean-burn engine category. The draft AP-42 section is being revised to eliminate the separate “clean-burn” engine categories. The final section may include both uncontrolled and LEC-equipped engines in the 2-stroke and 4-stroke lean-burn engine categories because of concern that LEC-equipped engines included in the test data cannot be identified conclusively.⁶ This discussion indicates that the “uncontrolled” emission factors given above may be based on data that include test results from lean-burn engines that would be considered controlled (i.e., LEC-equipped) for purposes of this report.

A 1996 GRI report includes emission test data for several lean-burn SI engines. These data include six 2-stroke engines representing five different models and three 4-stroke engines representing two different models. Each engine was tested from two to five times. For the 2-stroke engines, the average NO_x emission levels ranged from 4.9 g/bhp-hr to 20.8 g/bhp-hr. The 4-stroke engines averaged from 7.0 g/bhp-hr to 22.0 g/bhp-hr. In both cases, the test data were more concentrated toward the lower end of the range.⁷ These test results were among the data used to develop the 1997 draft revision for the AP-42 Section 3.2 discussed immediately above. This report discriminates clearly between engines equipped with LEC and those that are not.

A 1998 GRI report includes some NO_x emissions data generated during a project with Cooper Energy Systems to develop lower-cost CleanBurn™ retrofit technology for some Cooper-Bessemer 2-stroke lean-burn engine models often used in gas transmission applications. The report indicates that emissions of NO_x from a Cooper Z-330 engine that has not been retrofit range from 24 g/bhp-hr down to 2 g/bhp-hr as the air-to-fuel (A/F) ratio is made leaner. However, engine performance when leaned to below 7 g/bhp-hr is unacceptable due to increased fuel consumption, misfire, and elevated carbon monoxide and hydrocarbon emissions. The typical field operation level is not specified in the report, although the greatest fuel economy appears to be achieved at about the 16 g/bhp-hr level. The document also reports baseline (i.e., prior to retrofit) test results for a GMV-6 model (11.5 g/bhp-hr at 100 percent rated speed and torque) and a GMV-10-TF model (6 to 13 g/bhp-hr at rated conditions).⁸

Test data from Pacific Gas and Electric Company for two Cooper-Bessemer W-330 engines tested in 1995 show uncontrolled NO_x emissions of 18.9 and 16.7 g/bhp-hr (based on a typical conversion factor for lean-burn engines of 1 g/bhp-hr per 73 parts per million by volume [ppmv] at 15 percent oxygen).⁹ These engines were tested prior to being retrofitted with LEC technology.

Test data from Southern California Gas Company for two Ingersoll-Rand 412KVS engines tested in 1993 show uncontrolled NO_x emissions of 21.4 and 17.0 g/bhp-hr. These tests were conducted upstream of selective catalytic reduction (SCR) control devices.

Several other documents reviewed for this report include information on uncontrolled NO_x emissions that was not based directly on test data (or, at least, the test data were not included or cited in the document). These are primarily general statements regarding NO_x emissions from knowledgeable sources. This information is described briefly below:

- A 1990 GRI report states that uncontrolled NO_x emissions for natural gas pipeline engines (both lean burn and rich burn) range from about 7 g/bhp-hr to 26 g/bhp-hr.¹⁰ The report reflects the prime mover population prior to widespread use of newer lean-burn engines equipped with LEC technology.
- A 1992 paper prepared for a meeting of the Society of Petroleum Engineers by Cooper Industries personnel states that, prior to regulation, NO_x emissions from natural gas-fired engines ranged from 10 g/bhp-hr to 20 g/bhp-hr.¹¹ This range would include both lean-burn and rich-burn SI engines.
- A 1997 report prepared by the Manufacturers of Emission Controls Association (MECA) indicates that the typical NO_x emission level for natural gas-fired engines operated slightly lean of the stoichiometric A/F ratio is 18.0 g/bhp-hr.¹²
- A 1994 article in the *Oil & Gas Journal* states that natural gas compressor station engines typically emit NO_x at 15 g/bhp-hr.¹³ This would include both lean-burn and rich-burn engines.
- A knowledgeable representative of Southern California Gas Company stated during a site visit that NO_x emissions from the Delaval HVA16C engines at the facility were around 28 g/bhp-hr on hot days, prior to being retrofitted with LEC technology.
- Product literature from the Ajax Superior Division of Cooper Energy Services indicates that uncontrolled NO_x emissions from the Ajax line of relatively small 2-stroke lean-burn engines (110 bhp to 720 bhp) range from 3.0 g/bhp-hr to 9.5 g/bhp-hr. This information indicates that uncontrolled NO_x emissions from the Superior line of 4-stroke lean-burn engines (825 bhp to 2650 bhp) range from 15.0 g/bhp-hr to 22.1 g/bhp-hr.¹⁴

Another major source of information on uncontrolled NO_x emissions from lean-burn SI engines is the 1993 ACT document. For that document, the EPA collected information from 8 major engine manufacturers on 290 models of IC engines of all types in 1991 and 1992. While most manufacturers provided emissions data only for current (at that time) production engines, some included older engine lines, as well.¹⁵ We were not able to obtain the original information to review for this report. We have assumed that the data comprises guaranteed emission levels for the represented engine models.

The 1993 ACT document presents an average uncontrolled NO_x emission level for lean-burn SI engines of 16.8 g/bhp-hr. This value was calculated based on manufacturers' information on 122 models.¹⁶ The 1993 ACT document did not provide separate uncontrolled NO_x emission factors for 2-stroke and 4-stroke lean-burn engines.

3.1.2 Discussion and Conclusions on Uncontrolled NO_x Emissions from Lean-Burn SI Engines

The primary sources of data on uncontrolled NO_x emissions are engine manufacturers (in the form of guarantees) and emission tests. As discussed above, general statements regarding uncontrolled emissions may be made by sources familiar with these types of primary data.

In Section 3.1.2.1 below, we present considerations related to information from engine manufacturers. Section 3.1.2.2 presents considerations related to emission test results. In Section 3.1.2.3, the potential division of lean-burn SI engines into 2-stroke and 4-stroke subcategories is discussed. Section 3.1.2.4 presents conclusions regarding the appropriate uncontrolled NO_x emission levels for purposes of this report.

3.1.2.1 Discussion of NO_x Emissions Information from Engine Manufacturers.

Emissions data from engine manufacturers may tend to overstate emissions to some degree because the manufacturer may be liable if the engine fails to meet emissions guarantees. This potential liability motivates the engine manufacturer to elevate the emissions guarantee to a level that ensures that each individual engine in the model line will meet it. The guaranteed level also must account for the range of operating and ambient conditions to which the guarantee applies. On the other hand, the manufacturer is not motivated to inflate guaranteed emissions unnecessarily because this might make the engines less desirable to many potential customers. Based on these factors, we believe that engine manufacturers' guarantees provide a reasonable upper bound on uncontrolled NO_x emissions from well-maintained, well-operated engines.

Although the data were not available for this study, we believe that the engine manufacturers provided this type of information for the 1993 ACT document. As noted above, the value in that document for the average uncontrolled NO_x emission level for lean-burn SI engines was calculated based on manufacturers' information on 122 models of 2-stroke and 4-stroke engines.

The 1993 ACT document tabulated and averaged the uncontrolled NO_x emissions from lean-burn SI engines in five rated horsepower ranges. The overall average uncontrolled NO_x emission level for these engines was calculated as the weighted average of these averages (weighted by the number of engine models for which data were provided in each horsepower range). Thus, in effect, the overall average for lean-burn SI engines was calculated as the straight, unweighted average NO_x emission level of the engine models for which the manufacturers provided uncontrolled NO_x emissions data.

Given available data, this approach is appropriate. In an ideal situation, one might choose to calculate average uncontrolled emissions based on the actual in-use IC engine population, i.e., calculating an average weighted on the number of each model in service and the rated

horsepower of each. However, complete data are not available on the distribution of IC engines by model and size across the entire engine population. Even if such data were available, it is very likely that manufacturers' guarantees for uncontrolled NO_x emissions would be unavailable for many engine models, particularly older, discontinued models. In addition, manufacturers and operators may modify a model's design over time, so current information on uncontrolled emissions may not apply to older versions of the same engine model.

To examine the potential effect of weighting manufacturers' guaranteed uncontrolled NO_x emission levels by horsepower, we recalculated the average for lean-burn SI engines using the data in the 1993 ACT document. For each horsepower range, we multiplied the number of engine models in the range by the horsepower at the midpoint of the range to compute the total capacity for the range. (For the "greater than 4,000 bhp" range, we used 6,000 bhp.) We then computed the weighted average uncontrolled NO_x emissions based on these range capacities. The result was a weighted average of 17.0 g/bhp-hr, only 1 percent different than the unweighted average. When the exercise was repeated for the two rated horsepower ranges greater than 2,000 bhp (i.e., the engines most likely to be affected by EPA's NO_x SIP call or the related FIP), the resulting weighted average was 16.8 g/bhp-hr, which is the same value originally computed for the 1993 ACT document.

3.1.2.2 Discussion of Emission Test Data on NO_x Emissions. In contrast to the conservatism of manufacturers' guarantees, emission tests give an accurate reading of how a particular IC engine performed during a particular test period. However, owners typically have the opportunity to tune their engines prior to testing because emission tests are nearly always scheduled by the engine owner and conducted by a testing firm hired by the engine owner. This ability may affect the relationship between test results and the long-term emissions achieved by the engine. (This statement is not to imply that engine operators routinely manipulate emission test results in a gross manner. Nevertheless, many operators may adjust operation of emission sources, within the range of normal operations, to achieve the most favorable emission rate for the facility during testing.)

As discussed later in Section 4.1.4, when a controlled engine is tested for compliance purposes, the operator may tune the engine to minimize NO_x emissions prior to the test. In such cases, it is reasonable to conclude that test results represent a floor on the NO_x emission level achieved by the tested engine under the operating and ambient conditions of the test. In the case of uncontrolled IC engines, it is not so clear how the existing test data discussed above in Section 3.1.1 are likely to be related to long-term NO_x emissions. This uncertainty stems from the fact that we do not know why most of these tests were conducted.

Different types of regulatory requirements can exert upward or downward pressure on uncontrolled emission test results. For example, an "uncontrolled" engine might be subject to an emission limit that could be met through certain constraints on its operating parameters. While the owner of such a regulated, uncontrolled engine would adjust and operate the engine to reduce NO_x emissions to the required level, operators of unregulated engines of the same type would not need to make such adjustments. Thus, emission test results from an uncontrolled engine that is subject to emission limits may not be representative of other, unregulated engines of the same

model. The owner of an uncontrolled engine conducting a test to determine major or minor source status might also have an interest in minimizing the tested NO_x emissions.

In contrast, an emission test on an uncontrolled engine might be carried out prior to installing emission controls to establish the baseline for evaluating percent control and/or emission reduction credits to be generated upon control of the source. In this situation, it would be to the facility's advantage to maximize the tested NO_x emissions.

A third potential situation is the research study. The 1996 GRI document discussed above reports the test results of such a study. In such cases, one would expect the engines to be adjusted to represent typical, well-operated facilities. An unbiased study would not be expected to motivate adjustments either to minimize or to maximize NO_x emissions.

We do not know the circumstances of most of the testing that has been carried out on uncontrolled lean-burn SI engines, particularly that which served as the basis for the 1994 GRI document, the current AP-42 section (1996), and the draft revised AP-42 section (1997) on these engines. Thus, we cannot draw firm conclusions regarding the relationship of these data to typical long-term NO_x emissions.

Another unknown regarding the test data is how representative the data are of the general population of lean-burn SI engines. However, it should be pointed out that the data summary in the 1994 GRI document indicates that test data from a wide variety of engine models and sizes were reviewed for that report. In addition, the current AP-42 section (1996) assigns an A rating (excellent) to the emission factors for 2-stroke and 4-stroke lean-burn SI engines. This rating, while somewhat subjective, generally means that the factors were developed from A-rated test data from many randomly chosen facilities in the industry population.

On the other hand, the authors of 1997 draft revision to the AP-42 section rejected some of the data used for the 1996 AP-42 section on the grounds that the emission tests were not conducted using currently approved test methods and/or the tests did not include sufficient process data to characterize engine operation. The 1997 draft revision assigns an A rating to its NO_x emission factor for 2-stroke lean-burn SI engines, specifically meaning that the factor was developed from A-rated data from eight or more different engine models. This draft section's NO_x emission factor for 4-stroke lean-burn SI engines is assigned a B rating, meaning that the factor was developed from A-rated data from five to seven different engine models.

3.1.2.3 Discussion of Potential Subcategorization of Lean-Burn SI Engines. Some of the sources of information on uncontrolled NO_x emission discussed above in Section 3.1.1 distinguished between 2-stroke and 4-stroke lean-burn SI engines, with uncontrolled NO_x emissions from 2-stroke engines typically lower. These documents include the following:

- The 1994 GRI report includes separate emission factors for 2-stroke (12.5 g/bhp-hr) and 4-stroke (13.2 g/bhp-hr) lean-burn natural gas prime movers, based on emission test data. This represents a difference of about 5 percent. The report uses a

generalized emission factor of 13 g/bhp-hr for all lean-burn engines in the text discussion and in its analysis of the cost effectiveness of controls on these engines.¹⁷

- The current Section 3.2 of the AP-42 (1996) also addresses natural gas prime movers. This document characterizes uncontrolled NO_x emissions as 10.9 g/bhp-hr for 2-stroke engines and as 11.8 g/bhp-hr for 4-stroke engines, based on emission test data.¹⁸ This represents a difference of about 8 percent.
- The draft revision of the AP-42 section (1997) indicates NO_x emissions of 12.2 g/bhp-hr for 2-stroke engines and 15.0 g/bhp-hr for 4-stroke engines, based on emission test data.¹⁹ This indicates a difference of about 20 percent between average uncontrolled NO_x emissions from 2-stroke and 4-stroke lean-burn SI engines. However, this draft is undergoing significant further revision due to an inability to distinguish reliably between engines with and without LEC control technology. As a result, these emission factors cannot be considered final.
- The 1996 GRI document also differentiates between uncontrolled emissions from 2-stroke and 4-stroke engines. For the engines tested in that study, the average NO_x emission levels ranged from 4.9 g/bhp-hr to 20.8 g/bhp-hr for 2-stroke engines and from 7.0 g/bhp-hr to 22.0 g/bhp-hr for 4-stroke engines.²⁰ There is a great deal of overlap between these ranges.

These differences between uncontrolled NO_x emission levels for the two subcategories of lean-burn SI engines, while not trivial, certainly are not so great as to invalidate the use of a single emission level to characterize the entire lean-burn engine category. The variation among models within each subcategory is much greater than the differences between subcategories indicated in these documents, and there is a great deal of overlap. As noted, the 1994 GRI document reports separate emission levels for the two subcategories where the analysis of emission levels is detailed, but uses a combined emission level for the entire lean-burn category in other portions of the document, including the cost analysis.

The 1993 ACT document does not differentiate between 2-stroke and 4-stroke engines. The single uncontrolled NO_x emissions value in this document for lean-burn SI engines is based on information provided by major manufacturers of both 2-stroke and 4-stroke engines. Thus, this value is an average of data from both subcategories of lean-burn engines. The original data provided by the engine manufacturers for the 1993 ACT document were not available during preparation of this report. Thus, it was not possible to reevaluate the data to differentiate between 2-stroke and 4-stroke engines.

A number of the general statements regarding uncontrolled NO_x emissions cited previously in Section 3.1.1 do not differentiate among natural-gas fired engines at all. These statements provide an average value or typical range of values that would include rich-burn SI engines as well as 2-stroke and 4-stroke lean-burn engines.

3.1.2.4 Conclusions on Uncontrolled NO_x Emissions from Lean-Burn SI Engines. A single uncontrolled NO_x emission level of 16.8 g/bhp-hr published in the 1993 ACT document is appropriate and reasonable for the purposes of this report. While this value based on manufacturers' guarantees may represent the upper bound on well-operated and well-maintained lean-burn engines (as discussed previously in Section 3.1.2.1), it is also based on the most complete and most certain data set of the data reviewed for this report. Much of the other data presented above in Section 3.1.1 generally supports this value, including a number of sources of test data on individual engines. However, the information sources based on aggregated emission test data give lower values.

To reiterate, the uncontrolled NO_x emission level from the 1993 ACT document is based on information for 112 models of lean-burn SI engines gathered by the EPA in 1991 and 1992. Some manufacturers included data on older engine lines, as well as current production engines. We believe that these data are the most representative available for the existing stock of uncontrolled lean-burn engines.

With good maintenance, IC engines often have a very long life. For example, the 1994 GRI report indicates that many lean-burn IC engines used for natural gas compression, transmission, and storage have been in operation for several decades, with discontinued models having greater than 50 years of service.²¹ Thus, the in-use lean-burn engine population includes many engines manufactured before NO_x emissions were a concern.

Many lean-burn engine models currently in production incorporate low-NO_x technology. In fact, the term "lean burn" is often used today to refer to what we have defined as LEC technology for purposes of this report. This trend toward producing engines with inherently lower NO_x emissions increasingly is blurring the line between controlled and uncontrolled lean-burn engines. In fact, the 1997 draft AP-42 section defined 2-stroke and 4-stroke "clean burn" engines (i.e., engines equipped with LEC precombustion chamber technology) as separate engine families, distinct from other 2-stroke and 4-stroke lean-burn engines. This draft section attempted to provide uncontrolled emission factors for these clean burn engine families, instead of treating them as controlled lean-burn engines. However, the EPA has been unable to differentiate definitively between prechambered engines and other lean-burn engines in its NO_x emissions data. As a result, the next draft of the AP-42 section is expected to address only 2-stroke and 4-stroke lean-burn engines, combining all the test data without differentiating by combustion system technology.

This trend toward manufacturing LEC-equipped lean-burn engines was well underway when the data for the 1993 ACT were collected. However, it is clear from the data summary in that document that EPA did not include such engines in the uncontrolled data set. The NO_x emission level at the lower end of the each rated horsepower range exceeds the levels that are achieved using LEC technology.

The same cannot be said for the emission test data underlying the 1994 GRI report, the current AP-42 section (1996), or the draft revision to the AP-42 section (1997). The 1994 GRI report acknowledges that new, LEC-equipped engines are included in its data set. Although the

authors of the two AP-42 sections attempted to separate such engines from uncontrolled engines, there is some doubt as to whether they were entirely successful, as discussed previously.

Another factor favoring use of the NO_x emission level developed from manufacturers' data for the 1993 ACT document is the completeness of the data set, which includes 122 models of lean-burn SI engine. The test data from the other sources are not as comprehensive.

One potential drawback with the 1993 ACT NO_x emission level for lean-burn SI engines is that it does not differentiate between 2-stroke and 4-stroke engines. However, as discussed above in Section 3.1.2.3, we do not believe that the difference in NO_x emissions between these two types of engines is so great that a single, composite average is unacceptable. On the contrary, we believe that the advantages of the underlying data set outweigh this relatively minor shortcoming.

For the reasons discussed above, we believe that a factor of 16.8 g/bhp-hr for uncontrolled NO_x emissions for lean-burn SI engines is appropriate and reasonable for the purposes of this report. Accordingly, the cost analysis presented in Chapter 5 of this report is based on this uncontrolled NO_x emission level for this class of IC engines.

3.2 RICH-BURN SI ENGINES

This section presents and discusses information on uncontrolled NO_x emissions from rich-burn SI engines. Section 3.2.1 presents the information, and Section 3.2.2 provides a discussion of the information and presents conclusions.

3.2.1 Information on Uncontrolled NO_x Emissions from Rich-Burn SI Engines

Many of the same information sources discussed above for lean-burn engines also contain NO_x emission factors based on aggregated test data or include actual test results for rich-burn engines. The information on rich-burn engine NO_x emissions from these sources is summarized briefly in the paragraphs that follow.

The 1994 GRI report includes a NO_x emission level for rich-burn natural gas prime movers of 8.6 g/bhp-hr. The emission levels included in the report are based on an extensive data base of emission test results, although the number of rich-burn engine tests is not stated. The reported emission level is a weighted average, based on the natural gas prime mover population and on horsepower. The report notes that emissions from these engines typically range from 4 g/bhp-hr to 26 g/bhp-hr, while a few models have very low emissions. (The lowest test result that appears in the report is 1 g/bhp-hr.)²²

The current AP-42 Section 3.2 on natural gas prime movers characterizes uncontrolled NO_x emissions as 10.0 g/bhp-hr for rich-burn engines, based on emission test data. The section assigns an A rating (excellent) to this emission factor. As noted previously, this document includes many of the same test data references as the GRI report discussed above, including compilations of test data prepared for the natural gas industry that contain the bulk of the test

results considered.²³ Differing averaging methodology may explain the difference between this emission factor and that in the GRI report.

The 1997 draft revision for AP-42 Section 3.2 indicates uncontrolled NO_x emissions of 20.9 g/bhp-hr for rich-burn engines, based on eight emission test data points. This emission factor is rated B (above average).^{24, 25}

The 1996 GRI report includes emission test data for two uncontrolled rich-burn SI engines of the same model at one facility. Uncontrolled emissions were tested for each engine from two to four times. One of these engines averaged 7.7 g/bhp-hr over four tests, and the other averaged 14.4 g/bhp-hr over two tests. It is of interest to note that the engine with lower NO_x emissions had carbon monoxide emissions nearly 40 times those of the engine with higher NO_x emissions. Engine adjustments often involve tradeoffs between NO_x and carbon monoxide emissions, although there is no information available in the report to allow a conclusive interpretation of the results.²⁶

Several other documents noted above in Section 3.1.1 include information on uncontrolled NO_x emissions that was not based directly on test data. These are primarily general statements regarding NO_x emissions from knowledgeable sources. This information is described briefly below:

- The 1990 GRI report states that uncontrolled NO_x emissions for natural gas pipeline engines (both lean burn and rich burn) range from about 7 g/bhp-hr to 26 g/bhp-hr.²⁷ The report reflects the prime mover population prior to widespread regulation of these engines.
- The 1992 paper prepared for a meeting of the Society of Petroleum Engineers by Cooper Industries personnel states that, prior to regulation, NO_x emissions from natural gas-fired engines (both lean burn and rich burn) ranged from 10 g/bhp-hr to 20 g/bhp-hr.²⁸
- The 1997 report prepared by MECA indicates that typical NO_x emission levels for natural gas-fired engines operated slightly rich of the stoichiometric A/F ratio range from 8.3 to 11.0 g/bhp-hr.²⁹
- A 1994 article in the *Oil & Gas Journal* states that natural gas compressor station engines typically emit NO_x at 15 g/bhp-hr.³⁰ This would include both lean-burn and rich-burn engines.

The 1993 ACT document is a comprehensive source of data on uncontrolled NO_x emissions from uncontrolled rich-burn SI engines. This document presents an average uncontrolled NO_x emission level for these engines of 15.8 g/bhp-hr. This value was calculated based on manufacturers' information on 83 models.³¹

3.2.2 Discussion and Conclusions on Uncontrolled NO_x Emissions from Rich-Burn SI Engines

Much of the discussion related to lean-burn SI engines above in Section 3.1.2 applies to rich-burn SI engines, as well. The paragraphs that follow briefly discuss the manufacturer information and test data information reviewed for this project.

As discussed previously for lean-burn SI engines, manufacturers' guaranteed uncontrolled NO_x emission levels provide a reliable upper bound on actual emissions from well-maintained, well-operated engines. Potential liability may motivate engine manufacturers to elevate emissions guarantees slightly to ensure that each individual engine within the model line will meet the guaranteed levels.

The manufacturers' data behind the 1993 ACT document's analysis of uncontrolled NO_x emissions is very comprehensive. Data on 83 engine models provided by several engine manufacturers were included in the analysis. While most manufacturers supplied data only on current production models, some provided data on older models, as well. This is important because with good maintenance, IC engines often have a very long life. For example, the 1994 GRI report indicates that many rich-burn engines used in these natural gas compression, transmission, and storage were installed as early as the 1940's.³²

It is not clear that the test data underlying the uncontrolled NO_x emission factors from other sources is as comprehensive. We are not able to evaluate from the information reviewed for this study how representative the tested population is. It should be noted that the 1994 GRI report indicates that a large data base of test results from many models of rich-burn engines in the natural gas industry was used to develop the uncontrolled NO_x emission factor (8.6 g/bhp-hr) presented in that document. Using much of the same data, the 1996 AP-42 section assigned an A rating to its emission factor (10.0 g/bhp-hr). However, the 1997 draft AP-42 section dropped some of the data used in the other two documents, indicating that the tests were not conducted using currently approved test methods and/or the tests did not include sufficient process data to characterize engine operation. Using the more limited data (eight tests on from five to seven engine models), the 1997 draft AP-42 section arrived at a B-rated emission factor of 20.9 g/bhp-hr.

Product literature from one engine manufacturer provides an example of the enormous effect engine adjustments can have on uncontrolled NO_x emissions. This manufacturer lists four different carburetor settings for its rich-burn engine families: (1) Lowest Manifold (Best Power), (2) Equal NO_x and CO, (3) Catalytic Converter Input (3-way), and (4) Standard (Best Economy). For all the engine families and models, the Lowest Manifold setting (operating slightly fuel rich with an excess air ratio of 0.97) gives the lowest NO_x emissions, ranging from 8.5 g/bhp-hr to 12 g/bhp-hr. The Standard setting (operating slightly fuel lean with an excess air ratio of 1.06 to 1.12) results in the highest NO_x emissions, ranging from 18.0 to 28.0 g/bhp-hr. For every engine family, the Standard setting results in emissions at more than twice the level of the Lowest Manifold setting, with one model at nearly three times (28.0 versus 9.5 g/bhp-hr).³³

The tested NO_x level upstream of an add-on control device is sometimes represented as “uncontrolled” test data. However, some control devices, such as nonselective catalytic reduction (NSCR), dictate certain engine adjustments. For the rich-burn engine families presented in the product literature discussed above, the Standard (Best Economy) carburetor setting results in NO_x emissions from 50 to 75 percent higher than the Catalytic Converter Input setting.³⁴ Thus, “uncontrolled” test data from an engine equipped with an NSCR control system may be significantly lower than actual uncontrolled emissions from the same model engine in the absence of the control system (or other constraints on emissions).

For this reason, “inlet” values from NSCR-equipped engines in available data bases of emission test results were not analyzed for this report. Similarly, test results from engines equipped with prestratified charge (PSC) control technology with the PSC system turned off were not analyzed. (In the case of PSC, we have no information to indicate whether the modifications necessary to install PSC would affect “uncontrolled” emissions measured with the PSC system turned off.) We were unable to evaluate the test data underlying the 1994 GRI report, the 1996 AP-42 section, or the 1997 draft AP-42 section to determine whether any of the “uncontrolled” NO_x emissions data were from controlled engines (particularly NSCR-equipped engines).

Based on the discussion above, the uncontrolled NO_x emission level of 15.8 g/bhp-hr published in the 1993 ACT document is appropriate and reasonable for the purposes of this report. While this value based on manufacturers’ guarantees may represent the upper bound on well-operated and well-maintained lean-burn engines, it is also based on the most complete and most certain data set of the data reviewed for this report. The 1993 ACT document’s analysis of uncontrolled NO_x emission levels remains the most comprehensive and representative analysis to date. Much of the other data presented above in Section 3.2.1 generally supports this value. The range of values in the information sources based on aggregated emission test data (i.e., the 1994 GRI report, the 1996 AP-42 section, and the 1997 draft AP-42 section) span this value.

3.3 REFERENCES FOR CHAPTER 3

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4.0 UPDATE ON NO_x CONTROL TECHNOLOGIES

This chapter presents information on nitrogen oxides (NO_x) control technologies for stationary reciprocating internal combustion (IC) engines that has been generated since EPA published its *Alternative Control Techniques Document–NO_x Emissions from Stationary Reciprocating Internal Combustion Engines* (the 1993 ACT document).¹ This chapter updates the information in the 1993 ACT document, but is not intended to replace it. For example, this chapter does not present an in-depth description of the control technologies; the reader should refer to the 1993 ACT document for a complete description of each control technology.

For purposes of this report, “control technologies” include any measures undertaken primarily to reduce NO_x emissions. This definition includes modifying or adjusting the combustion system to reduce NO_x formation, as well as installing add-on control devices to remove NO_x from the engine exhaust. The definition includes modifying engine design to produce new engines with inherently lower NO_x emissions. Thus, for example, new engines manufactured with low-emission combustion (LEC) technology are considered controlled, just as are engines retrofitted with LEC. In contrast, turbocharging and intercooling alone are not necessarily considered NO_x control technologies (despite the fact that they typically reduce NO_x emissions) because these technologies may be introduced primarily to increase power and efficiency.

This chapter focuses primarily on LEC technology (Section 4.1), with less extensive updates on selective catalytic reduction (SCR) in Section 4.2, nonselective catalytic reduction (NSCR) in Section 4.3, and prestratified charge™ (PSC) technology in Section 4.4. Section 4.5 presents information on high-energy ignition system (HEIS) technology, which was not addressed in the 1993 ACT document. Section 4.6 presents information on emerging NO_x control technologies that have been developed since release of the 1993 ACT document. References for the entire chapter appear in Section 4.7.

This chapter concentrates on the more effective control technologies because these controls are of primary interest in nonattainment areas seeking significant emission reductions from IC engines. The chapter does not address air-to-fuel (A/F) ratio adjustment, ignition timing retard, or a combination of the two; see the 1993 ACT document for a discussion of these less effective technologies.²

4.1 LOW-EMISSION COMBUSTION TECHNOLOGY

This section on LEC updates Section 5.2.5 of the 1993 ACT document, which addresses application of LEC to lean-burn, spark-ignited (SI) engines. This section includes a brief description of the technology (Section 4.1.1) and its applicability (Section 4.1.2), new information on NO_x emissions (Section 4.1.3), a discussion of the emissions data (Section 4.1.4), and conclusions regarding the level of NO_x emissions achievable using LEC (Section 4.1.5).

4.1.1 Technology Description–LEC

Low-emission combustion in IC engines involves modifying the combustion system to achieve very lean combustion compared to the A/F ratios that are used in “conventional” lean-burn engines. The additional combustion air acts as a heat sink, lowering the temperature in the cylinder and reducing NO_x formation.

To deliver the additional combustion air required for LEC, turbocharging and intercooling capacity normally are required. In retrofit situations, this typically involves upgrading or replacing the turbocharger and intercooler, or adding this equipment where it is not already present (i.e., on naturally aspirated engines). Although they typically reduce NO_x emissions, turbocharging and intercooling alone do not qualify as LEC because additional engine modifications are required to minimize NO_x emissions and because these technologies may have been originally introduced to improve engine performance. However, turbocharging and intercooling are integral to LEC technology; in LEC applications they are considered part of the control system.

Other equipment associated with increased air flows may also need to be modified for LEC, such as the air intake and filtration system, the intercooler radiator, and the exhaust system and muffler. To maintain the optimum A/F ratio, an automated A/F ratio controller typically is used.

The challenge with this very lean combustion is to achieve proper ignition and stable combustion. Vendors of LEC technology (i.e., engine manufacturers and third-party retrofitters) have met these requirements with some combination of improved combustion chamber design, enhanced air-fuel mixing, and improved ignition systems.

In many cases, a precombustion chamber is used for enhanced ignition. In this system, ignition is initiated in a small chamber in a fuel-rich environment. The flame propagates rapidly and forcefully from this chamber into the main combustion chamber, providing uniform ignition of the very lean air-fuel mixture in the main chamber, as well as improved mixing.

Some engine manufacturers offer their smaller engines with “open chamber” LEC design. These engines feature a redesigned combustion chamber, rather than a precombustion chamber. These open-chamber LEC designs typically incorporate improved air-fuel mixing systems to achieve stable combustion under very lean conditions.

Engines with open-chamber LEC technology typically are designed for excess air levels only slightly above 50 percent, while engines with precombustion chambers typically are designed for excess air levels of 75 percent to over 100 percent. Consequently, prechambered engines have generally lower NO_x emissions than do open-chamber models.

Low-emission combustion based on precombustion chamber technology has been in use for about 20 years, when Cooper-Bessemer began manufacturing CleanBurn™ engines. Subsequently, other engine manufacturers began to manufacture LEC-equipped engines (open chamber and/or prechambered models). Presently, all major manufacturers of lean-burn SI engines offer LEC-equipped models, and many models are available only with LEC. At least two manufacturers offer some models that are available either in a rich-burn configuration or in an LEC configuration.^{3, 4}

Shortly after beginning to offer new LEC-equipped engines, some engine manufacturers began to offer retrofit “kits” and installation services for existing engines. Originally, the retrofits involved completely replacing the cylinder heads with redesigned heads and replacing or modifying numerous other engine components. The retrofit cylinder heads are cast with a precombustion chamber within the interior of the head. This type of retrofit was all that was commercially available at the time the data were gathered for the 1993 ACT document. These retrofits understandably involve relatively high capital costs, although the incremental expense is reduced if the retrofit is undertaken when the cylinder heads and other engine components are to be replaced anyway as part of an engine overhaul.

In more recent years, simpler and less expensive LEC retrofit technologies have been developed. One advance has been the development of “screw-in” precombustion chambers. These precombustion chambers screw into the existing spark plug hole in each cylinder head, eliminating the need to replace the existing cylinder heads. These screw-in precombustion chambers now are offered for retrofits by some engine manufacturers, as well as by third-party vendors. In addition, advances have been made in upgrading existing turbocharging systems, with the result that retrofits do not as often require replacement of the turbocharger. Contemporary retrofits may involve modifications to improve air-fuel mixing, as well, such as installing higher-pressure fuel valves. Chapter 5 includes a reevaluation of LEC retrofit costs based on more recent capital cost data.

4.1.2 Applicability of LEC

Low-emission combustion technology is applicable to IC engines fired with gaseous fuels. This includes both SI engines and dual-fuel engines operating in dual-fuel mode (as opposed to firing only diesel fuel). No additional information on dual-fuel engine applications was gathered for this report; refer to the 1993 ACT document for information on LEC technology for dual-fuel engines.

New SI engines equipped with LEC technology are, by definition, lean-burn engines. Both 2-stroke and 4-stroke lean-burn SI engines equipped with LEC technology are available in a full range of sizes, and many models are available only with LEC.

Low-emission combustion retrofit equipment and services are generally available, particularly for the most plentiful engine models. Cooper Energy Services, maker of Cooper-Bessemer, Ajax, Superior, and Delaval engines provides CleanBurn™ retrofits for all of its larger models and offers these services for engines manufactured by other companies, as well.^{5, 6, 7} Dresser-Rand, manufacturer of Ingersoll-Rand, Clark, and Worthington engines also offers retrofit services for its lean-burn engines.⁸ The Waukesha Engine Division of Dresser Industries manufactures two engine families that are available either in rich-burn or LEC configurations. The company offers LEC retrofit services for those engines originally sold in the rich-burn configuration.⁹ At least three third-party vendors (Diesel Supply Company; Enginuity, Inc.; and Emissions Plus, Inc.) offer retrofit services for a wide variety of engine makes and models. These vendors will work with any model engine, although economies of scale can reduce capital costs for plentiful engines. For other engines, customized precombustion chambers can result in somewhat higher costs.¹⁰

This report evaluates LEC retrofits only for lean-burn engines. In practice, although not impossible for rich-burn engines (as noted above for certain Waukesha engine families), LEC retrofits are primarily applied to lean-burn engines. Other control technologies, notably NSCR and PSC, are much more common for rich-burn engines. These technologies are discussed in later sections of this chapter.

4.1.3 Data on NO_x Emissions from LEC-Equipped IC Engines

For this report, we reviewed a variety of information on LEC performance that has become available in the years since the 1993 ACT document was published. This information includes information from LEC technology vendors, test data, analyses of test data carried out by EPA and others, and other “anecdotal” data obtained from a variety of sources. These new data are presented below in Sections 4.1.3.1 through 4.1.3.3. Section 4.1.3.4 summarizes the LEC test data.

4.1.3.1 Information from LEC Vendors. Information from several engine manufacturers indicates that they guarantee NO_x emissions at or below 2.0 grams NO_x per brake horsepower hour (g/bhp-hr) for nearly all new LEC-equipped engines. Some new models are guaranteed at up to 3.0 g/bhp-hr, but these are smaller models with open-chamber designs. These smaller engines are generally less than 1,200 bhp. Some new models are guaranteed to 1.0 g/bhp-hr.¹¹

Information from engine manufacturers that provide retrofit equipment and services indicates guaranteed levels typically in the range from 1.5 to 3.0 g/bhp-hr.¹² These guarantees reflect the performance of standard retrofit “kits” that have been developed by these engine manufacturers. A number of sources have indicated that retrofits can be tailored to meet a target emission level, although the cost may be greater than for the standard retrofit kit.^{13, 14, 15}

One third-party retrofitter has guaranteed emissions as low as 1.0 g/bhp-hr. This vendor has retrofitted approximately 125 engines to improve NO_x emissions. These retrofits are designed to achieve the applicable emission limit on a site-specific basis, so not all have involved LEC. Approximately one third of these retrofits have been guaranteed to meet 2.0 g/bhp-hr or

lower, and all guarantees have been met. Many of the vendor's other retrofits have achieved this level as well, based on test data. This vendor estimated that 90 percent of engine models can be retrofitted to achieve 2.0 g/bhp-hr using the screw-in precombustion chambers the company manufactures, along with associated upgrades to the turbocharger, intercooler, air-fuel mixing system, etc.¹⁶

This vendor cannot achieve 2.0 g/bhp-hr for some engine models. In particular, some Worthington models are designed so that adequate air cannot be delivered to achieve the necessary A/F ratio. The design of others prevents adequate air-fuel mixing. In some Worthington engines, the precombustion chamber is extended deep inside the cylinder head, which makes chamber cooling and engine misfires a real concern. This vendor has achieved a level of 6 g/bhp-hr for certain Worthington engines.^{17, 18} As an example of uncontrolled emissions from Worthington engines, the vendor indicated that he has measured the uncontrolled emissions of one Worthington Model SUTC located in New York at 18 to 22 g/bhp-hr and another located in the Gulf Coast at 24 to 28 g/bhp-hr using a portable NO_x emissions monitor (uncertified).¹⁹

The vendor noted that the original engine manufacturers have the capability to reduce NO_x emissions to lower levels on engines that third-party vendors find problematic. The engine manufacturers are able to replace engine parts, such as the cylinder heads, with redesigned parts to overcome the impediments to low NO_x emissions. However, significant use of redesigned parts involves increased costs.²⁰

The information provided by engine manufacturers does not suggest any notable difference in the guaranteed NO_x emission level for new 2-stroke and 4-stroke lean-burn engines equipped with LEC. Similarly, no significant difference based on operating cycle is apparent in the guaranteed performance of engines retrofit with LEC.

It should be noted that NO_x emission guarantees most often are made for specific operating conditions, typically firing pipeline-quality natural gas and operating at 100 percent of rated speed and torque. Most sources of information indicate that NO_x emissions are highest at full load and fall as load declines.^{21, 22, 23} However, some sources indicate otherwise, and emission test results sometimes show an inconsistent relationship between NO_x emissions, engine speed, and engine torque.^{24, 25, 26} All sources indicate that guaranteed NO_x emission levels can be maintained over a wider operating range through the use of good A/F ratio controls.

4.1.3.2 Emission Test Data. A considerable body of test data has accumulated in the years since LEC was first introduced. Some of the data were available when the 1993 ACT document was developed, but additional data have come available in the intervening years. Test data and associated analyses that were reviewed for this report are summarized in the paragraphs that follow. Except as otherwise noted, the test data are from short-term emission tests conducted at or near rated speed and load. Where necessary, test data were converted to brake-specific terms using a factor of 1 g/bhp-hr per 75 parts per million by volume (ppmv), dry basis, at 15 percent oxygen, consistent with the 1993 ACT document.²⁷

A May 2000 memo prepared by the EPA compiles data from seven different sources of NO_x emission test data. In all, the memo summarizes the results of 269 emission tests conducted on 49 different engines, including a wide variety of makes, models, and sizes. The memo notes that only 11 of the 269 tests exceeded 2 g/bhp-hr; 96 percent of the test results were below this level. Only one test was above 4 g/bhp-hr, and 71 percent of the tests were below 1 g/bhp-hr. A few of these tests were conducted under part speed, part load conditions.²⁸

One of the sources of data compiled in the EPA memo discussed above is the Ventura County, California, Air Pollution Control District (VCAPCD). Ventura County has regulated IC engine NO_x emissions since 1981. As a result, VCAPCD has an extensive data base of short-term emission test results, including many engines that have been tested multiple times over the years. The version of the data base evaluated for the EPA memo includes test data only through 1992. A more recent version of the data base, including data through 1999, was obtained for this report. This version of the data base includes the results of 320 tests conducted on 23 engines equipped with LEC. Eight different engine models are included, with five models of 4-stroke engines and three models of 2-stroke engines. The NO_x emissions range from a low of 0.08 g/bhp-hr up to a high of 4.0 g/bhp-hr, with a mean of 0.66 g/bhp-hr. Only two of the tests (less than 1 percent) are greater than 2.0 g/bhp-hr. Almost 86 percent of the tests are below 1.0 g/bhp-hr, and nearly 32 percent are below 0.5 g/bhp-hr.²⁹

A 1998 paper based on the VCAPCD emission test data base examined long-term test results for three engine models equipped with LEC technology. For these three engine models, the results were as follows:

- Ajax DPC-180 (180-bhp, 2-stroke engine): Sixty-eight individual tests were conducted on four different engines fired with natural gas between 1982 and 1996. The engines averaged NO_x emissions of 0.6 g/bhp-hr, with a high of 1.1 g/bhp-hr and a low of 0.2 g/bhp-hr.
- Waukesha L7042GL (1,100-bhp, 4-stroke engine): One hundred twenty-eight individual tests were conducted on eight different engines fired with natural gas between 1987 and 1995. The engines averaged 0.8 g/bhp-hr, with a high of 2.3 g/bhp-hr and a low of 0.2 g/bhp-hr. Besides the one test at 2.3 g/bhp-hr, the remaining tests were at or below 1.9 g/bhp-hr, with most well below this level.
- Superior 16SGTA (2,650-bhp, 4-stroke engine): Eighty-nine individual tests were conducted on three different engines fired with landfill waste gas between 1986 and 1997. The engines averaged NO_x emissions of 0.7 g/bhp-hr, with a high of 1.2 g/bhp-hr and a low of 0.3 g/bhp-hr.³⁰

Another source of data included in the EPA memo discussed above is the Santa Barbara County, California, Air Pollution Control District (SBCAPCD). A recent version of the SBCAPCD emission test data base, including data from 1991 through 1999, was obtained and evaluated. This data base contains results for 14 NO_x emission tests conducted on 4 engines equipped with LEC. Of these, the results of 12 tests on 3 engines included NO_x data that could

be converted to terms of grams NO_x per brake horsepower hour. These 12 tests averaged about 0.5 g/bhp-hr, ranging from a low of 0.14 g/bhp-hr to a high of 0.67 g/bhp-hr.³¹

Test data from the San Diego County, California, Air Pollution Control District (SDCAPCD) also were reviewed for this report. These data include the results of 121 NO_x emission tests conducted between 1991 and 1996 on 13 engines equipped with LEC. Overall, the emissions ranged from 0.3 g/bhp-hr to 4.8 g/bhp-hr with a mean of 1.1 g/bhp-hr.³²

Eleven of the engines represented in the SDCAPCD data are of open-chamber LEC design. In 107 tests, NO_x emissions from these engines ranged from 0.4 g/bhp-hr to 4.8 g/bhp-hr, with a mean of 1.2 g/bhp-hr. Only one test was over 3.0 g/bhp-hr, and five tests were between 2 and 3 g/bhp-hr. Fifty-two percent of the tests were between 1 and 2 g/bhp-hr, and 42 percent were less than or equal to 1 g/bhp-hr. By engine, the highest average NO_x emission rate was 1.5 g/bhp-hr, and the lowest was 0.9 g/bhp-hr.

The two remaining engines included in the SDCAPCD data are prechambered models fired with landfill waste gas. In 14 tests, these engines averaged NO_x emissions of 0.5 g/bhp-hr, with a range from 0.3 to 1.0 g/bhp-hr.

Another source of NO_x emission data is the EPA's *Compilation of Air Pollutant Emission Factors*, commonly known as the "AP-42." This document presents emission factors for various types of emission sources based on aggregated source test data. The current AP-42 section on IC engines was published in October 1996. This section lists the following two NO_x emission factors for 2-stroke, lean-burn engines equipped with LEC:

- Clean Burn—2.3 g/bhp-hr
- Precombustion Chamber—2.9 g/bhp-hr

We believe that this terminology corresponds to trademarks used by two engine manufacturers that offer precombustion chamber LEC technology. These technologies are not differentiated in this report; both are considered LEC.

The AP-42 assigns these emission factors a rating of C, or average. The references for the AP-42 section reveal that the test data behind these factors are from 1990 or earlier.³³ The AP-42 section does not state that the data are from short-term emission tests, but this appears likely based on the references. The engine operating conditions (load and speed) of the testing are not specified in the section.

The EPA has begun a revision of the AP-42 section on IC engines. A draft section dated February 1997 was posted on the Internet for public comment. This draft section classifies lean-burn engines equipped with LEC as distinct "engine families" and specifies the following terminology and NO_x emission factors:

- 2-stroke clean-burn engines—1.1 g/bhp-hr
- 4-stroke clean-burn engines—0.5 g/bhp-hr

These emission factors are rated C (average) and D (below average), respectively. The draft AP-42 section includes some more recent references, as well as some of the same references as the current section.^{34, 35}

Commenters from industry on the draft AP-42 section objected to the “clean burn” designation. They noted that “CleanBurn” is a trademark of Cooper Energy Systems. Today, many engine manufacturers refer to their engines equipped with precombustion chambers simply as “lean-burn engines.” The EPA has recognized that it is unable to distinguish with certainty between engines with and without prechamber LEC technology on the basis of the test reports it is using to develop the revised AP-42 section. As a result, the EPA plans to further revise the section.

Additional NO_x emission test information obtained for this report are summarized below:

- Seven Clark Model TLA-6, 2-stroke, lean-burn, 2,000-bhp engines retrofitted with LEC, tested in April 1998. Six engines retrofitted by a third-party vendor ranged from 0.8 to 1.4 g/bhp-hr, with a mean of 1.0 g/bhp-hr. One engine retrofitted by the original equipment manufacturer (OEM) tested at 1.7 g/bhp-hr.³⁶
- Three Ingersoll-Rand Model 412KVS, 4-stroke, lean-burn, 2,000-bhp engines retrofitted with LEC by the OEM, tested in August 1992. Tested at 0.51, 0.62, and 0.64 g/bhp-hr, with a mean of 0.59 g/bhp-hr.³⁷
- One Cooper-Bessemer Model GMV-10C, 2-stroke, lean-burn, 1,100-bhp engine retrofitted with LEC by the OEM, tested in September 1999. Tested at 0.61 g/bhp-hr.³⁸
- Five Delaval Model HVA16C, 4-stroke, lean-burn, 5,500-bhp engines retrofitted with LEC by the OEM. Test results from June 1991 (four engines) and May 1996 (three engines) range from 0.43 to 0.68 g/bhp-hr, with a mean of 0.59 g/bhp-hr.³⁹
- Two Cooper-Bessemer Model W-330, 2-stroke, lean-burn engines retrofitted with LEC by the OEM, tested in 1995 or 1996. Tested at 1.0 and 1.3 g/bhp-hr.⁴⁰
- Two engines retrofitted as a research project for the OEM attempting to develop a lower-cost retrofit kit. One Cooper-Bessemer Model GMV-6, 2-stroke, lean-burn engine tested at 1.4 g/bhp-hr immediately after the retrofit (September 1992), at 2.4 g/bhp-hr after the A/F ratio controller was adjusted to achieve low NO_x emissions over the widest range of operating conditions (September 1992), and at 1.8 g/bhp-hr after 4,000 operating hours (April 1993). These emission levels all were measured at rated load and speed. One Cooper-Bessemer Model GMV-TF-10, 2-stroke, lean-burn

engine was tested after retrofit at a variety of horsepower ranging from approximately 50 percent to 110 percent of rated horsepower. The maximum NO_x emission level was about 5 g/bhp-hr and the minimum was less than 0.5 g/bhp-hr. All but one test point were at or below about 4 g/bhp-hr. The emission rate generally increased as the horsepower increased. (The uncertainty for this engine stems from test results displayed only in a plot of emissions versus horsepower.) The research project report indicated that both these engines met their target NO_x emission rates (2 to 5 g/bhp-hr).⁴¹

In all, the sources of NO_x emission test data summarized above include the results of 476 individual tests conducted on 58 engines. (This count does not include the aggregated data in some of the sources discussed above, such as the May 2000 EPA memo and the AP-42 sections.) In these tests, NO_x emissions ranged from 0.1 g/bhp-hr to 4.8 g/bhp-hr. Ninety-seven percent of these tests (460) found emissions less than or equal to 2 g/bhp-hr. Almost 75 percent (356) of the tests found emissions less than or equal to 1 g/bhp-hr, and 25 percent (120) found emissions of less than or equal to 0.5 g/bhp-hr. Only two tests measured NO_x emissions greater than or equal to 4 g/bhp-hr. The emission test data are summarized by information source in Table 2-1 of Chapter 2 of this report.

4.1.3.3 Other Information on LEC Performance. Some additional information on the level of NO_x emissions that is achievable with LEC technology was obtained for this report. This “anecdotal” information consists of statements regarding LEC performance that are not accompanied by documentation (e.g., test data) or vendor guarantees. The additional information is summarized below:

- A 1990 report prepared for the Gas Research Institute (GRI) states that new engines equipped with precombustion chamber LEC technology can often achieve NO_x emission levels of 2 g/bhp-hr or below, corresponding to 80 to 90 percent reduction from conventional spark plug designs. The report indicates that this technology is well demonstrated in retrofit applications for newer, turbocharged lean-burn engines, and ascribes the same 80 to 90 percent emission reduction to such retrofits.⁴²
- A 1994 report prepared for GRI states that an engine retrofitted with precombustion chamber LEC technology can average NO_x emissions of less than 2 g/bhp-hr, but for purposes of its cost analysis assumes emissions of 2.5 g/bhp-hr. The report notes that retrofits have been carried out and successfully demonstrated on many lean-burn engines, with the most likely candidates for retrofit being newer model designs. The report also states that improvements are routinely incorporated into the retrofit kits. This is the final report for a project developed in 1991 and 1992.⁴³
- Three GRI flyers from 1994 and 1995 advertize new, low-cost NO_x controls for Ingersoll-Rand, Clark, and Cooper-Bessemer engines. The controls offered are the newer generation of OEM LEC retrofit technologies, featuring such improvements as screw-in precombustion chambers and turbocharger upgrades. The flyers indicate that the retrofit controls can reduce NO_x emissions to below 3 g/bhp-hr, which appears to

be the target level based on expectations at that time regarding upcoming reasonably available control technology (RACT) requirements for lean-burn engines.⁴⁴

- A paper prepared by the Manufacturers of Emission Controls Association (MECA) in 1997 indicates that NO_x emissions of 0.7 g/bhp-hr are typical from natural gas-fired engines operating at 74 percent excess air (lambda equal to 1.74).⁴⁵ Engines operating at such excess air levels typically require precombustion chambers to achieve stable combustion.
- Material submitted to the EPA by the Interstate Natural Gas Association of America (INGAA) in 1999 states that most existing engine models with OEM LEC retrofit equipment can achieve 4 g/bhp-hr at 100 percent torque and 100 percent speed. However, INGAA stated that some engines with poor air-fuel mixing characteristics can achieve only 7 g/bhp-hr at 100 percent torque and speed. The latter engines include some models manufactured by Worthington (ML and UTC models). This material also indicates that OEM LEC retrofit technology is available for most lean-burn engine models found at natural gas transmission and storage facilities, but is not available for a few models.⁴⁶
- Southern California Gas Company operates continuous emissions monitoring systems (CEMS) on five engines equipped with LEC at a natural gas storage facility.⁴⁷ Based on knowledge of the CEMS data, the company has indicated that NO_x emissions from the engines are typically about 1.0 g/bhp-hr, and normally range from about 0.5 to 3.0 g/bhp-hr.⁴⁸ (Three of these engines are the Ingersoll-Rand Model 412KVS for which August 1992 emission test data are presented in the preceding section.)

Another source of information on achievable NO_x emissions is the 1997 California Air Resources Board (CARB) proposed determinations of RACT and best available retrofit control technology (BARCT) for stationary IC engines. These proposed determinations have not yet been finalized.

The proposed NO_x RACT for lean-burn SI engines is an 80 percent reduction in emissions, or emissions not to exceed 125 ppmv, dry basis, at 15 percent oxygen. This emission level corresponds to 1.7 g/bhp-hr based on the conversion factor used in this report for LEC-equipped engines. The basis for the proposed NO_x RACT is the VCAPCD rule that applied between September 1989 and December 1993. The CARB document also cites the VCAPCD test data in support of the proposed level. The document indicates that LEC is expected to be the most popular means of meeting the RACT requirements, although SCR may be used as an alternative if LEC is unsuitable for a particular model engine.

The proposed NO_x BARCT for lean-burn SI engines is a 90 percent reduction in emissions, or emissions not to exceed 65 ppmv, dry basis, at 15 percent oxygen. This corresponds to 0.9 g/bhp-hr. The basis for the proposed NO_x BARCT is the current VCAPCD rule, the Federal Implementation Plan for the Sacramento area, and the Sacramento Metropolitan Air Quality Management District rule. The proposed BARCT is identical to the latter two rules,

but less stringent than the current VCAPCD rule (94 percent control or 45 ppmv limit). The CARB document also cites the VCAPCD test data to support the proposed level, noting that the majority of tests showed compliance with the proposed level despite the fact that the applicable requirement at the time of testing was 125 ppmv. The document indicates that LEC is expected to be the most common control method for meeting the proposed BARCT, although SCR may be used as an alternative if LEC is unsuitable for a particular model engine.⁴⁹

4.1.4 Discussion of NO_x Emissions Data for LEC

The primary sources of data on controlled NO_x emissions are control equipment vendors (in the form of guarantees) and emission tests. As discussed above, general statements regarding achievable emissions may be made by sources familiar with these types of primary data.

Emissions data from LEC vendors (both engine manufacturers and third-party retrofit vendors) may overstate emissions somewhat. The vendor typically must provide a performance guarantee to the engine owner, leaving the vendor potentially liable if the engine fails to meet the guaranteed emission level.

This potential liability may motivate the control equipment vendor to design the LEC system to comfortably meet guaranteed performance, which is generally dictated by regulatory requirements. The typical result is LEC-equipped engines that meet or outperform the guarantee, as evidenced by information from retrofit vendors that all installations have met guaranteed emission levels, by one vendor's statement that many retrofits guaranteed at higher levels have achieved NO_x emissions of 2 g/bhp-hr, and by the test data discussed above that are consistently well below the applicable emission limits.^{50, 51} Given these considerations, vendor guarantees provide a reasonable upper bound on NO_x emissions from well-maintained, well-operated engines equipped with LEC technology.

In contrast to the conservatism of guarantees, emission tests give an accurate picture of how a particular IC engine equipped with LEC performed during a particular test period. However, test results may tend to understate long-term emissions from the tested engine because owners may typically tune engines to minimize NO_x prior to testing. For example, a 1994 rule effectiveness study in Ventura County, California found that 5 out of 22 engines subjected to unannounced emission testing (23 percent) violated the NO_x limit. In comparison, the study found that only 1 out of 11 engines (9 percent) failed the regularly scheduled annual compliance test. One of the conclusions of the study was that most non-compliant engines can come into compliance easily and quickly with minor adjustments. (The source of these data does not identify the types of controls included in the study. Nonselective catalytic reduction clearly was included; it is not clear whether LEC was included.)⁵² Because nearly all emission testing is scheduled by the engine owner, it is reasonable to conclude that test results represent a floor on the NO_x emission level achieved by the tested engine under the operating and ambient conditions of the test.

Other factors can also confound the relationship between test data and the performance of which a control technology is capable. Control systems typically are designed to meet the

emission limits that apply to each individual engine. Therefore, test data from controlled engines do not necessarily reflect what the technology is capable of achieving, but rather what the engine is required to meet. In addition, control technologies evolve and improve over time as vendors and operators gain experience. For this reason, older test results may not reflect the emission levels achievable with current technology.

4.1.5 Achievable NO_x Emissions from Lean-Burn SI Engines Equipped with LEC

Based on information from engine manufacturers, available emission test data, and the considerations presented in the preceding section, 2.0 g/bhp-hr is representative of the NO_x emission level achieved across all new engines equipped with LEC, including open-chamber designs. Among new engines equipped with precombustion chamber LEC technology (which includes some smaller engines and all larger engines), this level is achieved by all models.

Further, 2.0 g/bhp-hr also is a representative NO_x emission level that can be achieved in nearly all LEC retrofit situations, based on the use of precombustion chambers and associated equipment. Suppliers of retrofit equipment and services (both engine manufacturers and third-party vendors) typically guarantee NO_x levels in the range from 1.5 to 3.0 g/bhp-hr. However, a number of sources have indicated that retrofits can be tailored to the emission limit the engine is required to meet, so, for example, 2.0 g/bhp-hr is often achievable even for engines where the guarantee associated with the standard retrofit kit is higher. Nevertheless, it is to be expected that some engines will not be able to achieve 2.0 g/bhp-hr, particularly certain Worthington models.

The NO_x emission test results discussed previously support the conclusion that 2.0 g/bhp-hr is achievable for new engines and most engines retrofitted with LEC technology. While emission test results generally represent a floor on the long-term emissions from a particular engine, the available test data are dominated by very low NO_x test results, in some cases numerous tests of the same engines over the course of years. The test results from California are frequently well below the applicable NO_x emission limits, which were in the range of 2 g/bhp-hr when most of the tests were conducted. These data suggest a long-term emission level no greater than 2.0 g/bhp-hr for the tested engines.

4.2 SELECTIVE CATALYTIC REDUCTION

This section on SCR primarily updates Sections 5.2.4, 5.3.1.2, and 5.3.2.2 of the 1993 ACT document, which address application of SCR to lean-burn SI engines, diesel compression-ignition (CI) engines, and dual-fuel CI engines, respectively. The primary reason for the update is to describe new SCR technology and its implications for IC engines in load-following service. This section includes a brief description of the technology (Section 4.2.1) and its applicability (Section 4.2.2), information gathered on SCR for this report (Section 4.2.3), and conclusions regarding the level of NO_x control achievable using SCR (Section 4.2.4).

4.2.1 Technology Description–SCR

Conventional SCR technology, as described in the 1993 ACT document, involves injecting anhydrous ammonia into the exhaust gas stream upstream from a catalyst bed. As the exhaust passes through the catalyst bed, the ammonia and NO_x react to form nitrogen gas and water. The system typically includes a NO_x CEMS upstream and/or downstream of the catalyst bed as a feedback mechanism to ensure that the proper quantity of ammonia is injected to avoid emissions of either unreacted ammonia or NO_x .

In recent years, the technology has been undergoing a change. The systems marketed today typically use an aqueous solution of urea in place of anhydrous ammonia as the reducing agent. This reduces the hazard and handling costs associated with anhydrous ammonia, because urea is not classified as a hazardous material as anhydrous ammonia is. Sometimes an aqueous solution of ammonia is used, which is less hazardous than anhydrous ammonia, although not as safe as urea.

For urea systems, the first stage of the catalyst bed is a hydrolysis catalyst, which converts the urea to ammonia. In the second stage of the catalyst, the ammonia and NO_x react to form nitrogen gas and water. As a beneficial secondary reaction, hydrocarbons react with oxygen to form water, carbon dioxide, and some carbon monoxide. The third stage of the catalyst bed is an oxidation catalyst where any unreacted ammonia is oxidized to nitrogen gas and water. A beneficial secondary reaction in this stage is the oxidation of carbon monoxide to carbon dioxide.

These systems use a “feedforward” system for determining the urea injection rate based on engine operating parameters (load, speed, and type of fuel, if variable) and exhaust temperature. The feedforward system is essentially a predictive emissions monitoring system (PEMS). The PEMS is calibrated by “mapping” the engine as part of the SCR system installation. Some systems complement the feedforward system with a feedback NO_x CEMS downstream from the catalyst to “trim” the urea injection rate.^{53, 54, 55}

4.2.2 Applicability of SCR

As discussed in the 1993 ACT document, the types of IC engines that SCR can be applied to include lean-burn SI engines, diesel CI engines, and dual-fuel CI engines. To date in the United States, diesel engines are the most prevalent applications. Available data gathered for this report indicate that at least 44 IC engines at 12 facilities have had SCR installed since 1991. Thirty-eight of these are CI engines, with 31 fired with diesel fuel, 4 fired with distillate fuel oil (#2), 1 fired with residual fuel oil (#6), and 1 dual-fuel engine fired with diesel and natural gas. The remaining seven engines are lean-burn SI engines fired with natural gas. These include three engines at a natural gas pipeline compressor station in Southern California. Most of these SCR systems use anhydrous ammonia, although at least six of the engines use urea as the reducing agent. One source indicates that there are over 700 IC engines controlled with SCR systems in Europe and Japan, including approximately 80 to 100 2-stroke engines. (From the context, we believe that the source of this last data meant 2-stroke lean-burn SI engines fired with natural gas, although it is not explicit in the reference.)^{56, 57, 58, 59}

An issue with SCR technology has been its ability to maintain a high level of control, while minimizing emissions of unreacted ammonia (referred to as “ammonia slip”), on IC engines in load-following applications. This issue has specifically been raised for natural gas-fired, lean-burn SI engines at natural gas compressor stations. The potential problems associated with load following include variations in NO_x emissions, variations in exhaust gas flow and temperature, and thermal cycling (rising and falling gas temperature, which can degrade the catalyst). The natural gas transmission industry does not believe these concerns have been resolved sufficiently for their applications.⁶⁰ Vendors of SCR equipment believe that these issues have been addressed in modern, feedforward systems using improved catalysts.

4.2.3 Information on SCR-Equipped Engines

Although SCR technology was not a major focus, some information came to light during data gathering for this report. This information includes one facility’s operational experience with SCR, some emission test data, and information from vendors of modern SCR equipment.

One facility that was visited for this project discussed experiences with SCR control on one lean-burn SI engine from 1984 to 1996. The SCR system met or exceeded the guaranteed level of NO_x control (70 percent), allowing the facility to meet the applicable emission limit. However, the facility found the system difficult and expensive to operate. Operating expenses included the CEMS needed for control system feedback, the anhydrous ammonia reducing agent, and catalyst replacement. The facility found operation and maintenance difficult because it required work beyond that normally required for an engine. The CEMS was especially problematic because it required facility personnel to learn new analytical and instrumental skills. Some neighbors objected to the facility transporting and storing the hazardous anhydrous ammonia. The company ultimately took this engine out of service, as well as a second identical engine controlled with SCR at another facility, shifting all duty to LEC-equipped engines located at these sites.⁶¹ Emission test results from 1993 for these two engines show outlet NO_x emissions of 2.86 and 2.80 g/bhp-hr, corresponding to reductions of 87 and 84 percent, respectively.⁶²

The VCAPCD emission test data base includes seven lean-burn SI engines equipped with SCR control technology. Five models ranging from 291 bhp to 800 bhp are represented. In 49 tests of these engines, NO_x emissions ranged from 0.1 g/bhp-hr to 3.0 g/bhp-hr, with a mean of 1.1 g/bhp-hr. Six tests of three engines (two different models) found emissions greater than 2 g/bhp-hr. For 43 tests, NO_x emissions upstream of the catalyst bed also were provided, allowing the percent reduction to be calculated. The reductions ranged from 41 to 97 percent, with an average percent reduction of 84 percent.

The test dates in the VCAPCD data range from 1986 to 1993. During this period, lean-burn SI engines were subject to a NO_x emission limit of 125 ppmv, dry basis, at 15 percent oxygen, or an emission reduction of 80 percent. In all but two tests of one engine, the test results indicate compliance with at least one of these alternative standards. The engine that failed two emission tests was taken out of service after the second test.

In 1993, the VCAPCD tightened the NO_x emission limit for lean-burn SI engines to 45 ppmv, dry basis, at 15 percent oxygen, or an emission reduction of 94 percent. We do not know what the phase-in period for the new limits was, but the VCAPCD data base includes no test results for lean-burn SI engines equipped with SCR after 1993. This suggests that these engines were removed from service. The data base indicates that three of the seven engines were removed from service and replaced with electric motors.⁶³ According to a 1998 paper by a representative of the VCAPCD, one aim of VCAPCD's tighter NO_x emission limits was to encourage electrification of IC engines.⁶⁴

Test result summary data also were obtained for 1997 emission tests of three 3,130-bhp, 4-stroke, lean-burn SI engines equipped with SCR control systems, which we believe to be urea based. These engines are located at a liquid fuel pipeline pumping station and operate at variable load and variable speed depending on the quantity, pressure, and density of the fuel being pumped. The SCR system utilizes a feedforward system based on engine load and speed and on exhaust temperature. The engines are subject to stringent permit emission limits for NO_x, volatile organic compounds (VOC), and carbon monoxide which correspond to 15 ppmv, 25 ppmv, and 32 ppmv, respectively (all on a dry basis corrected to 15 percent oxygen). This NO_x limit corresponds to about 0.2 g/bhp-hr. During testing in January 1997, the engines achieved the NO_x and carbon monoxide limits, but exceeded the limit for VOC. In repeat testing in March 1997 after the catalyst was checked and cleaned, the engines achieved all the emission limits. In 20 individual test runs on these three engines, NO_x emissions ranged between 0.11 g/bhp-hr and 0.21 g/bhp-hr.^{65, 66, 67}

These test results indicate that SCR can achieve design NO_x control levels during short-term emission tests, including, in the case of the VCAPCD data, multiple tests on the same engine over the course of several years. However, these test results do not directly address performance during engine load swings. Continuous emissions data are necessary to address this issue fully.

We obtained one plot of continuous data over a 10 minute period from a trade association that includes SCR vendors. This figure plots data from a heavy duty diesel truck engine equipped with a feedforward urea SCR system. During this period, the engine varied from a speed of about 700 rotations per minute (rpm) at idle to about 2,300 rpm, with load varying concurrently from nearly 0 foot-pounds (ft-lbs) to about 800 ft-lbs. Inlet NO_x concentrations varied closely with load, ranging from a less than 10 ppmv up to over 150 ppmv. Outlet NO_x concentrations remained relatively stable, varying from nearly 0 ppmv up to about 20 ppmv. It is not clear from the figure at what percent oxygen the NO_x concentrations are expressed.⁶⁸

Vendors of SCR systems indicate that the feedforward controls on modern systems provide for excellent NO_x control in load-following applications. One representative indicated that the advance in technology has been driven by the interest of diesel engine manufacturers, working with catalyst vendors, in developing urea SCR for on-road vehicles. Such vehicles exhibit varying load by nature.⁶⁹ Another source also stressed that the PEMS feedforward system, with optional CEMS feedback system, has been advanced by a strong research and

development effort. This vendor has supplied such SCR systems for a variety of applications, including stationary IC engines, ship engines, railroad engines, and diesel truck engines.⁷⁰

Selective catalytic reduction system vendors also believe that they have solved other problems with SCR systems for IC engines. Advances in catalysts have eliminated thermal shock and vibration impacts and broadened the available temperature operating window.⁷¹

Vendors of SCR systems typically indicate that NO_x control efficiencies greater than 90 percent are achievable. These systems typically are designed on a case-by-case basis to achieve the required emission reduction, so design values do not necessarily represent the limit of the technology. One vendor source indicates that a number of SCR systems installed on U.S. IC engines since 1993 have been designed for NO_x control ranging from 80 percent to 95 percent. The design outlet NO_x emission level for three lean-burn SI engines at one natural gas pipeline compressor facility is less than 30 ppmv (oxygen concentration not specified by this information source). Another vendor source indicates that one urea SCR system installed in 1999 on a natural gas-fired, 389-bhp, lean-burn SI engine was guaranteed at 90 percent NO_x control, but has achieved over 95 percent control. Another such system on a diesel electric generator was designed for 70 percent reduction, but achieved 79 percent.^{72, 73}

4.2.4 Achievable Level of NO_x Control with SCR

Based on the information presented and discussed above, 90 percent control of NO_x emissions is generally achievable through use of SCR systems on IC engines, including lean-burn SI engines, diesel CI engines, and dual-fuel CI engines. Recent installations with lower control levels are the result of the systems' having been designed to meet applicable NO_x emission limits, rather than any inherent limitation of the technology.

Based on information provided by SCR vendors, the shortcomings of earlier SCR systems have been corrected by the new generation of the technology, which includes improved catalysts, PEMS feedforward system controls (with the option for supplemental CEMS feedback control, where desired), and use of urea as the reducing agent. However, this technology has yet to be widely demonstrated in the United States on lean-burn SI engines in load-following applications. Vendors of this technology still must convince U.S. lean-burn SI engine operators that modern SCR systems are as effective, reliable, easy to operate, and cost effective as alternative control technologies, most notably LEC.

4.3 NONSELECTIVE CATALYTIC REDUCTION

This section on NSCR primarily updates Section 5.1.5 of the 1993 ACT document, which addresses application of NSCR to rich-burn SI engines. This technology was not a focus for this effort, but some information was gathered during the course of the project. This section includes a brief description of the technology (Section 4.3.1) and its applicability (Section 4.3.2), information gathered on NSCR (Section 4.3.3), and conclusions regarding the level of NO_x control achievable using NSCR (Section 4.3.4).

4.3.1 Technology Description–NSCR

In NSCR, the engine exhaust is routed to a catalyst bed across which NO_x is reduced to nitrogen gas. At the same time, VOC and carbon monoxide are oxidized to water and carbon dioxide. Because emissions of these three pollutants all are reduced by the catalyst, NSCR is often referred to as a “three-way catalyst” system. These systems are similar to the catalytic converters used on automobiles.

For an NSCR system to operate optimally (i.e., to minimize NO_x emissions), the inlet exhaust stream must have very low oxygen content, as well as proper concentrations of NO_x, VOC, and carbon monoxide. This requires initial engine adjustments, followed by careful monitoring of oxygen content in the exhaust. For this reason, an automatic A/F ratio controller typically is used to regulate the exhaust oxygen content entering the catalyst bed. The controller adjusts the A/F ratio based on input from an oxygen sensor upstream from the catalyst bed.

The engine adjustments required to optimize NSCR systems typically reduce the efficiency of the engine, harming fuel economy. One source indicated that the brake-specific fuel consumption (BSFC) of these engines increases to 8,500 Btu/bhp-hr, at best.⁷⁴ Without the NSCR operating constraints, the BSFC is typically well below 8,000 Btu/bhp-hr for rich-burn engines, depending on model and other operational factors.

4.3.2 Applicability of NSCR

Because of the requirement for low oxygen content, NSCR systems are limited to rich-burn SI engines. As noted above, the engines must be adjusted to generate exhaust gas with specified characteristics.

4.3.3 Information on NSCR-Equipped Engines

A number of facilities in California that operate NSCR-equipped engines were visited during information-gathering for this report. The biggest operational problem associated with NSCR at these facilities has been damage to the catalyst caused by excessive temperature. This is caused when the exhaust stream is too fuel rich. In this situation, the uncombusted natural gas is rapidly oxidized in the catalyst bed, burning it out.

One natural gas storage facility that uses NSCR uses a bypass system during engine startup, in case the engine backfires and exhausts uncombusted fuel. The engine exhaust at this facility is typically about 950 °F. If the temperature reaches 1,200 °F, the system shuts down. At about 1,300 °F, the catalyst sustains damage. Another facility that uses NSCR-equipped engines to pump a variable water flow has had a significant problem with catalyst burnout.^{75, 76}

Most of the visited facilities have achieved applicable NO_x emission limits using NSCR. Depending on jurisdiction and installation date, these NO_x limits are equal to or less than 50 ppmv, dry basis, at 15 percent oxygen (approximately 0.75 g/bhp-hr). However, one facility with very low permitted emission levels (equivalent to about 0.2 g/bhp-hr) has had difficulty

maintaining this level. To improve system performance, this facility replaced the standard ignition systems on its engines with improved electronic ignition systems. A recent measure that has been successful for the facility has been to install an insulation blanket on the exhaust piping upstream from the catalyst bed, thereby maintaining a higher temperature when the exhaust stream reaches the catalyst bed. This has moved the exhaust into a temperature range where the NSCR system is more efficient.⁷⁷

At one facility visited for this project, the rich-burn engines are subject to emission limits of 50 ppmv for NO_x and 1,700 ppmv for carbon monoxide, both on a dry basis at 15 percent oxygen. The carbon monoxide limit is a facility-specific limit based on an offset agreement with the SBCAPCD; otherwise, the limit would be 4,500 ppmv. A facility representative indicated that tuning these NSCR-equipped engines to achieve the NO_x emission limit is relatively easy because of the less-restrictive carbon monoxide limit. In contrast, best achievable control technology (BACT) for new engines in California is 9.5 ppmv or 0.15 g/bhp-hr for NO_x and 225 ppmv or 0.6 g/bhp-hr for carbon monoxide (concentrations on a dry basis at 15 percent oxygen). This NO_x level is only achievable with rich-burn engines controlled with NSCR. The combination of these restrictive levels for both NO_x and carbon monoxide makes the engine operating window for compliance very narrow.⁷⁸

Emission test data for NSCR-equipped engines from three local air pollution agencies in California were reviewed for this report. These data from VCAPCD, SBCAPCD, and SDCAPCD are summarized below:

- The VCAPCD test data include 114 engines equipped with NSCR control technology. Forty-seven models ranging in size from 25 bhp to 1,250 bhp are represented in the data. In 902 tests of these engines, NO_x emissions ranged from less than 0.01 g/bhp-hr to 19 g/bhp-hr, with a mean of 0.3 g/bhp-hr. Ninety-nine percent of the tests (893) found emissions of less than 1 g/bhp-hr. For 543 tests, inlet NO_x emissions are included in the data base, allowing the percent reduction to be calculated. Percent reductions range from 0 to nearly 100 percent, with an average reduction of 92 percent. It should be noted that for the two tests with 0 percent emission reduction the inlet NO_x value was unusually low (0.12 and 0.03 g/bhp-hr), giving the appearance that the NO_x outlet value was mistakenly entered as the inlet value as well. Among tests that show NO_x reductions of less than 70 percent, the majority have NO_x inlet values of less than 2 g/bhp-hr.⁷⁹
- The SBCAPCD test data include 78 engines equipped with NSCR. Seventeen models ranging in size from 48 bhp to 747 bhp are represented. In 163 tests of these engines, NO_x emissions ranged from less than 0.01 g/bhp-hr to 1.5 g/bhp-hr, with a mean of 0.17 g/bhp-hr. Tests dates range from 1991 to 1999.⁸⁰
- The SDCAPCD test data include 33 engines equipped with NSCR. In 249 tests of 7 different models, NO_x emissions ranged from 0 g/bhp-hr (reported in the data we reviewed as 0 ppmv at 3 percent oxygen) to 18 g/bhp-hr, with a mean of about 1.0 g/bhp-hr. Fifty-eight percent of the tests found emissions less than or equal to

0.5 g/bhp-hr. Over 85 percent of the tests (217) found emissions of 2.0 g/bhp-hr or less. The tested engines apparently had site-specific emission limits, which ranged from 180 ppmv at 3 percent oxygen (equivalent to about 0.9 g/bhp-hr) to 456 ppmv at 3 percent oxygen (equivalent to about 2.2 g/bhp-hr). All but 1 of the 32 tests with emissions greater than 2.0 g/bhp-hr were out of compliance with their permitted NO_x limits; an additional 9 tests with emissions less than 2.0 g/bhp-hr were out of compliance. A percent NO_x reduction was provided for 27 tests of 7 engines. The reductions ranged from 87 to 100 percent, with a mean of 97 percent. Tests dates ranged from 1984 to 1996.⁸¹

Test result summaries for two additional NSCR-equipped engines not included in the data above were received from one natural gas storage facility in California. In these 1997 tests, the NO_x emissions from these engines were less than 10 ppmv (dry basis at 15 percent oxygen) and less than 0.1 g/bhp-hr.⁸²

As noted above in Section 4.1.3.3, another source of information on achievable NO_x emissions is the 1997 CARB proposed determinations of RACT and BARCT for stationary IC engines. These proposed determinations have not yet been finalized.

The proposed NO_x RACT for rich-burn SI engines is a 90 percent reduction in emissions, or emissions not to exceed 50 ppmv, dry basis, at 15 percent oxygen. This emission level corresponds to about 0.75 g/bhp-hr. The basis for the proposed NO_x RACT is the VCAPCD rule that applied between September 1989 and December 1993. The CARB document also cites the VCAPCD test data in support of the proposed level. The document indicates that NSCR is expected to be the most popular means of meeting the RACT requirements, although PSC may be used for engines fired with waste-derived fuels (e.g., landfill gas or sludge digester gas) where contaminants may poison the NSCR catalyst.

The proposed NO_x BARCT for rich-burn SI engines is a 96 percent reduction in emissions, or emissions not to exceed 25 ppmv, dry basis, at 15 percent oxygen. This corresponds to about 0.37 g/bhp-hr. (For engines fired with waste-derived fuel, the limits are 90 percent reduction of 50 ppmv.) The basis for the proposed NO_x BARCT is the current VCAPCD rule, the Federal Implementation Plan for the Sacramento area, and the Sacramento Metropolitan Air Quality Management District rule. The proposed BARCT is identical to these rules. The CARB document also cites the VCAPCD test data to support the proposed level, noting that the majority of tests showed compliance with the proposed level despite the fact that the applicable requirement at the time of most testing was 50 ppmv. The document indicates that NSCR is expected to be the most common control method for meeting the proposed BARCT, except for engines fired with waste-derived fuel. These engines are expected to use PSC.⁸³

Information from vendors of NSCR systems indicates that NSCR three-way catalysts have been installed on over 1,000 IC engines in the United States and have been in use for over 10 years. This source indicates that these catalyst systems reduce NO_x emissions by over 98 percent, while reducing VOC by 80 percent and carbon monoxide by over 97 percent.⁸⁴

4.3.4 Achievable Level of NO_x Control with NSCR

Based on the information presented and discussed above, 95 percent control of NO_x emissions is generally achievable through the use of NSCR systems on rich-burn SI engines. These systems typically are designed on a case-by-case basis to meet applicable emission limits, with percent reduction more a function of design than any inherent limitation in the control technology.

Consistent operation at this level of control requires an automatic A/F ratio controller and implementation by the facility of a good inspection and monitoring program. The inspection and monitoring program is necessary to ensure that engines remain adjusted to optimize the NSCR systems' effectiveness and to detect signs of catalyst inactivity at the earliest possible time.

4.4 PRESTRATIFIED CHARGE™

This section on PSC primarily updates Section 5.1.4 of the 1993 ACT document, which address application of PSC to rich-burn SI engines. This technology was not a focus for this effort, but some information was gathered during the course of the project. This information is presented briefly below.

Prestratified charge technology involves injecting air into the intake manifold so that during the intake stroke, the piston initially draws in air, followed by a fuel-rich air-fuel mixture. Thus, the mixture near the spark plug is fuel rich, promoting good combustion, while the mixture away from the spark plug is very lean, acting as a heat sink and suppressing NO_x formation. Prestratified charge technology is applicable only to carbureted (i.e., non-fuel-injected) rich-burn engines.

Some California facilities using PSC technology were visited during information-gathering for this report. In the mid-1980's, one company retrofitted seven engines at two facilities with PSC technology. These engines are used to generate electricity for onsite consumption. The technology has performed well, achieving NO_x emission reductions of 85 to 90 percent, although the vendor guarantee was for only 80 percent. However, the PSC retrofit has resulted in a 20-percent power derating for the engines. In addition, while the PSC system itself requires very little maintenance, the engines are more "touchy" and require more frequent overall maintenance. Results from 11 emission tests of these 7 engines submitted by this source show NO_x emissions ranging from 1.0 g/bhp-hr to 3.2 g/bhp-hr. The average over the tests is about 2.0 g/bhp-hr.^{85, 86}

Another facility located in the VCAPCD retrofitted several engines with PSC to meet the older emission standard that required a 90 percent reduction in NO_x emissions or a limit of 50 ppmv. When the VCAPCD standard was tightened to 96 percent reduction or 25 ppmv, the facility removed the PSC system and added NSCR. Other engines at this facility that are fired with waste-derived fuel continue to use PSC technology. These engines also use exhaust gas recirculation (EGR), with the air injected by the PSC system coming from the engines' exhaust.

Emission test data for PSC-equipped engines from two local air pollution agencies in California were reviewed for this report. These data from VCAPCD and SBCAPCD are summarized below:

- The VCAPCD test data include tests of 18 engines equipped with PSC control technology. Ten models ranging in size from 100 bhp to 800 bhp are represented. In 150 tests of these engines, NO_x emissions ranged from about 0.1 g/bhp-hr to 9.5 g/bhp-hr, with a mean of 0.6 g/bhp-hr. Eighty-nine percent of the tests (134) found emissions of less than 1 g/bhp-hr. The 16 tests with emissions greater than 1 g/bhp-hr were from 8 engines ranging in size from 300 bhp to 800 bhp. For 37 tests, the data base includes NO_x emissions without PSC so that the percent change in emissions can be calculated without and with control. (In a number of tests, it appears that the value without PSC is repeated from an earlier test without retesting.) In one test, the emissions increased by about 6 percent with PSC. In the remaining 36 tests, the lowest percent reduction is 90 percent, with an average reduction of 95 percent. The data base includes tests from 1987 to 1999.⁸⁷
- The SBCAPCD test data include tests of 32 engines equipped with PSC control technology. Six different models are represented in 126 tests. The engines range in size from 49.5 bhp to 410 bhp. Fifty-four tests (67 percent) were on engines of less than 50 bhp. Many of the engines are fired on field gas. These are likely to be cyclical load engines powering rod pumps in oil and natural gas fields. Emissions of NO_x ranged from less than 0.1 g/bhp-hr to 12.5 g/bhp-hr, with a mean of 1.3 g/bhp-hr. All of the fifteen tests (19%) that found emissions greater than 2.0 g/bhp-hr were on engines of less than 50 bhp. For 17 of the engines, there were comparison test runs with the PSC turned off and turned on. Emissions of NO_x with the PSC turned on were on average 77 percent less than with the PSC turned off. All these comparison tests were conducted on engines less than 50 bhp. Test dates ranged from 1991 to 1999.⁸⁸

The 1993 ACT document found that the achievable NO_x emission level for PSC is 2.0 g/bhp-hr, based on the vendor's guarantees. This value is generally consistent with the information gathered for this project and is a representative value for the NO_x emission level that can be achieved using PSC control technology.

4.5 HIGH-ENERGY IGNITION SYSTEMS

With traditional spark plug ignition, the life of the spark is very short—only a fraction of a degree of crankshaft rotation. If the mix of air and fuel in the area of the spark is not exact, there is poor combustion or no combustion at all. With HEIS technology, also known as plasma ignition systems, a continuous electrical discharge is provided at the gap of a conventional spark plug for 10 to 90 degrees of crankshaft rotation. This extended energy delivery ensures combustion will occur even in the leanest of conditions. High-energy ignition systems can be used only in lean-burn, natural gas-fired SI engines.

One well-known high-energy ignition system was developed by ENOX Technologies under the trade name of INOx™. With the INOx™ system, a very lean air-fuel mixture is fired using a turbocharger to boost pressure, thus reducing combustion temperatures. The lower combustion temperatures results in reduced NO_x formation. The electronic plasma combustion system ignites the mixture through a conventional spark plug opening; therefore, installation does not require modification to the engine's head and can be accomplished in 3 to 5 days.⁸⁹

During development, the INOx™ system was tested in the laboratory and on at least two field engines. The lowest NO_x emission level achieved on a 2,750-bhp V-275 Cooper-Bessemer engine while maintaining acceptable engine operation was 2.5 g/bhp-hr, an 84 percent reduction from the uncontrolled level.⁹⁰

Since that time, HEIS has been installed on numerous engines to meet NO_x RACT requirements in the range of 2.5 to 3.0 g/bhp-hr in the Eastern United States. One source indicates that a natural gas transmission company purchased INOx™ technology for installation on as many as 53 compressor station engines in New York and Pennsylvania.⁹¹ Another source indicates that ENOX has successfully retrofitted over 100 engines with its INOx™ technology. Several clients have reported over 80 percent reduction in NO_x emissions.⁹²

Another company, Plasmachines, Inc., has also developed HEIS technology that has been demonstrated on two operating IC engines. This ignition system has demonstrated the capability to reduce NO_x emissions from these engines from the level of 10 g/bhp-hr to the regulatory level at or near 2.0 g/bhp-hr.⁹³

Stack test data from between 1995 and 1998 for three Clark TLA-8 reciprocating engines retrofitted with HEIS technology (make unknown) found average NO_x emission rates ranging from 1.2 to 4.2 g/bhp-hr, with an average of 2.05 g/bhp-hr.⁹⁴ There is little information available on the effects of HEIS technology on other pollutants.

4.6 EMERGING NO_x CONTROL TECHNOLOGIES

Three emerging technologies that show promise for reducing NO_x emissions from IC engines were identified during information-gathering for this project. The SCONOx® system uses a single catalyst to remove NO_x, carbon monoxide, and VOC. The NOxTech® system uses a non-catalytic chemical reaction to reduce NO_x, particulate matter, VOC, and carbon monoxide emissions. High-pressure fuel injection enhances mixing of air and fuel in the combustion chamber. These emerging technologies are described briefly below.

4.6.1 SCONOx® Technology

The SCONOx® system, developed by Goal Line Environmental Technologies, uses a single catalyst to remove NO_x, carbon monoxide, and VOC. Initially applied to gas turbines, SCONOx® IC-N and IC-D have been developed for use on internal combustion engines that are, respectively, natural gas-fired and diesel-fired.

According to product literature, the SCONOx[®] process uses no hazardous materials; all utilities required to operate the system—natural gas, steam, water, ambient air, and electricity—are often already present at the site.⁹⁵ At temperatures between 300 and 700 °F, nitrogen dioxide (NO₂) is absorbed onto the catalyst surface through the use of a potassium carbonate coating, which reacts with the NO₂ to form potassium nitrites. The SCONOx[®] catalyst undergoes regeneration periodically to maintain the maximum NO_x absorption. The catalyst is regenerated by passing a controlled mixture of regeneration gases across its surface in the absence of oxygen. The regeneration gases react with the nitrites to form water and elemental nitrogen. Carbon dioxide in the regeneration gas reacts with potassium nitrites to form potassium carbonate—the absorber coating that was on the surface of the catalyst before the oxidation cycle began. Water (as steam) and elemental nitrogen are exhausted up the stack and potassium carbonate is once again present on the surface of the catalyst allowing the oxidation adsorption cycle to begin again. There is no net gain or loss of potassium carbonate.⁹⁶

Testing conducted by the vendor shows SCONOx[®] IC-N reduces NO_x, carbon monoxide, and VOC up to 95 percent in lean-burn engine exhaust.⁹⁷ Three SCONOx[®] IC-N systems were purchased for natural gas-fired IC engines and were scheduled to go on line in May 2000.⁹⁸

Cummins Engine Company is testing SCONOx[®] IC-D for use on mobile and stationary diesel IC engines.⁹⁹ Preliminary testing in diesel IC engines found the SCONOx[®] and the related SCOSOx[®] catalyst systems reduced NO_x by 98.9 percent to 0.4 g/bhp-hr.¹⁰⁰ The fuel penalty for use of these systems was 1 percent or less. Three SCONOx[®] IC-D units have been sold but have not yet been commissioned.

4.6.2 NOxTech[®] Emission Control System

According to product literature, the NOxTech[®] emission control system, developed by NOxTech Inc., involves chemically treating exhaust gases with a nonhazardous liquid chemical. NOxTech[®] can be used on both diesel and lean-burn natural gas-fired IC engines. It replaces the exhaust silencer on IC engines with a reaction chamber. The non-catalytic chemical reagent is injected into the exhaust at temperatures between 1,400 and 1,500 °F. The NO_x and reagent react to form nitrogen, water vapor, and carbon dioxide. There is no toxic waste, although there are trace ammonia emissions of less than 2 to 5 ppmv.¹⁰¹ The NOxTech[®] system is fully automated. Installation requires no major modifications and takes 2 to 3 weeks.

The exhaust gas must be heated to achieve the temperatures necessary for the NOxTech[®] system reactions. A heat exchanger is located downstream from the reactor to reclaim and reuse this heat energy.

The NOxTech[®] system has been installed and is operating on several diesel generators owned by Southern California Edison. Its Catalina Island facility uses NOxTech[®] on 2.5 MW and 3.8 MW diesel electric generators. Southern California Edison also uses NOxTech[®] on 1.5 MW and 2.8 MW diesel generators at its Pebbly Beach generating station.

According to the vendor, NOxTech[®] has been proven to remove 90 to 95 percent of NO_x, 60 to 80 percent of particulate matter, 90 percent of VOC, and 50 to 70 percent of carbon monoxide from the exhaust of the 4,000-bhp diesel-powered generator on Catalina Island.¹⁰² Based on its demonstrated commercial performance, NOxTech[®] has been demonstrated as BACT for some diesel engines.¹⁰³

4.6.3 High-Pressure Fuel Injection

Another technology with potential for reducing NO_x emissions from IC engines is the use of high-pressure fuel injector systems to enhance the mixing of air and fuel in the combustion cylinder. According to one vendor of NO_x control equipment and retrofit services, this technology represents a “second generation” LEC, which may accomplish the same emission reductions without requiring precombustion chambers or as much excess air. Reducing the quantity of excess air would diminish the turbocharging and intercooling retrofit requirements. High-pressure fuel injection could significantly reduce the cost and complexity of retrofitting IC engines to control NO_x emissions.¹⁰⁴

A representative of a company visited during this project to collect information on IC engine control technology discussed high-pressure fuel injection as a potential NO_x-reduction technology. He mentioned that in a test, a high-pressure fuel injection system reduced NO_x emissions by 80 percent from a large (around 5,000 bhp) turbocharged Clark engine. He also noted, however, that Clark engines typically have relatively poor mixing, so reductions from other engines might not be as great.¹⁰⁵

It should be noted that another LEC retrofit vendor stated that NO_x emissions cannot be reduced to 2 g/bhp-hr through the use of a high-pressure fuel system alone. This vendor noted that less stringent regulatory requirements can sometimes be met with a combination of ignition timing adjustment, high-pressure fuel injectors, and improved A/F ratio and ignition system controls. This vendor’s LEC retrofits typically include high-pressure fuel injectors.¹⁰⁶

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5.0 CONTROL COSTS

This chapter presents information on the costs associated with nitrogen oxides (NO_x) emission controls for stationary reciprocating internal combustion (IC) engines. The primary emphasis is on low-emission combustion (LEC) control for lean-burn, spark-ignited (SI) engines, for which an updated cost analysis is included in Section 5.1. Some cost data on modern selective catalytic reduction (SCR) systems are presented Section 5.2. Section 5.3 provides the references for this chapter.

5.1 COSTS FOR LEC NO_x CONTROL OF LEAN-BURN SI ENGINES

A primary emphasis of this report is to update the information on LEC technology for lean-burn SI engines, including costs. There are two reasons for this emphasis. First, many of the IC engines that will be affected by the NO_x State implementation plan (SIP) call in the Eastern United States are lean-burn SI engines. Second, developments in LEC technology have brought retrofit costs down in recent years. Accordingly, capital and annual costs have been reevaluated, as has cost effectiveness. In general, this cost analysis follows the methodology used in *Alternative Control Techniques Document–NO_x Emissions from Stationary Reciprocating Internal Combustion Engines* (the 1993 ACT document), which is based on the *OAQPS Control Cost Manual*.^{1,2} Deviations from that methodology are pointed out in the material below.

This section presents costs in terms of both 1990 and 1997 dollars. Costs in terms of 1990 dollars have been used for many past analyses produced by the U. S. Environmental Protection Agency's Office of Air Quality Planning and Standards (OAQPS), including the cost analysis for the NO_x SIP call affecting the Eastern United States. In recent years, a number of regulatory analyses prepared by OAQPS have been conducted in terms of 1997 dollars. To facilitate comparison with other analyses, this report presents both.

5.1.1 Capital Costs

Section 5.1.1.1 below discusses the methodology used to determine representative purchased equipment costs (PEC) for LEC retrofits. Section 5.1.1.2 presents the methodology for determining total capital investment (TCI), which includes expenses incurred by the facility in addition to the PEC. Section 5.1.1.3 presents additional cost data and a discussion of how site-specific and engine-specific factors influence costs.

5.1.1.1 Purchased Equipment Costs. One engine manufacturer and one third-party vendor provided actual installed costs for recent LEC retrofits in 1999 dollars.^{3,4} The cost data include costs for low-speed and medium-speed engines. The costs provided by the vendors are believed to represent the installed costs of all equipment related to the LEC retrofit, including any equipment required for increased air flows (e.g., inlet air filtration ductwork, exhaust silencers and ductwork, and aerial coolers). For this reason we have not inflated this hardware cost by a factor of 30 percent as was done for the LEC analysis in the 1993 ACT document.⁵

To conform to the 1993 ACT document analysis, this report assumes that the vendors' installed costs do not include such items as the purchaser's engineering and project management costs, field connections, painting, and training. (The third party vendor's cost data included a number of such items, but costs were aggregated in such a way that these items could not be backed out.) Accordingly, we have treated the vendor cost data as the purchased equipment costs (PEC).

After adding in the cost of an electronic air-to-fuel (A/F) ratio controller, the vendors' cost data were aggregated and plotted against horsepower, and a linear regression was carried out. Figure 5-1 presents the results. As can be seen from the figure, the data are reasonably linear (R-square value of 0.78). There is no sign of the pronounced divergence between costs for low-speed and medium-speed engines presented in the 1993 ACT document. In addition, no one contacted during the preparation of this report indicated that LEC costs differ substantially between low-speed and medium-speed engines. Accordingly, this report addresses LEC costs for all lean-burn SI engines together, without the subdivisions used in the 1993 ACT document. Based on the regression analysis, PEC ranges from \$171,000 for a 1,000 brake horsepower (bhp) engine to \$444,000 for an 8,000 bhp engine.

5.1.1.2 Total Capital Investment. To account for costs incurred by the facility beyond the PEC, we followed the 1993 ACT document methodology in applying the following cost elements: (1) direct installation—25 percent of PEC, (2) indirect installation—20 percent of PEC, (3) contingency—20 percent of PEC, (4) sales tax—3 percent of PEC, and (5) freight—5 percent of PEC. To calculate TCI, we summed PEC and these five cost elements. Figures 5-2a and 5-2b present the results in 1990 dollars and 1997 dollars, respectively. To de-escalate the LEC equipment costs from 1999 dollars to 1990 and 1997 dollars, the *Chemical Engineering* plant cost indices for each year were used. See Chapter 2, Tables 2-2a and 2-2b for a summary of TCI values for selected engine sizes in 1990 dollars and 1997 dollars, respectively.

5.1.1.3 Discussion of Capital Costs. The current capital cost of LEC retrofits was discussed with representatives of one natural gas supply company during site visits and follow-up contacts. The company has a current estimate for a third-party retrofit of a Clark Model HSRA, 2-stroke, 1,000 bhp, 8-cylinder engine at a pipeline station. The estimate for the total capital investment for this project, which would use screw-in precombustion chambers, is \$710,000, including \$570,000 to be paid to the LEC vendor and \$140,000 in in-house expenses. The estimate includes \$93,000 for an oxidation catalyst to reduce carbon monoxide emissions, as will be required in this Southern California air pollution control district if carbon monoxide emissions

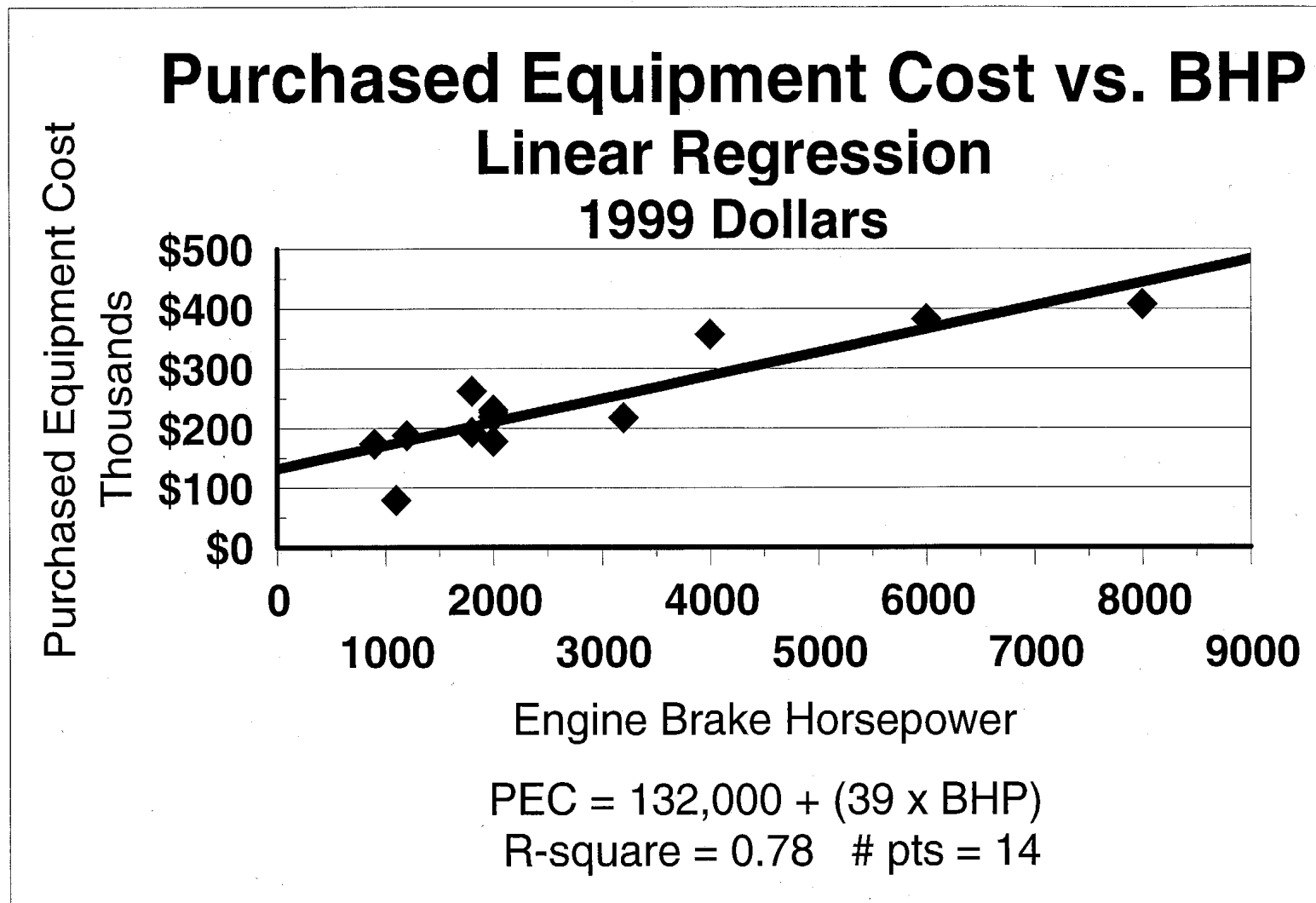


Figure 5-1. Purchased equipment cost for LEC retrofit versus rated brake horsepower.

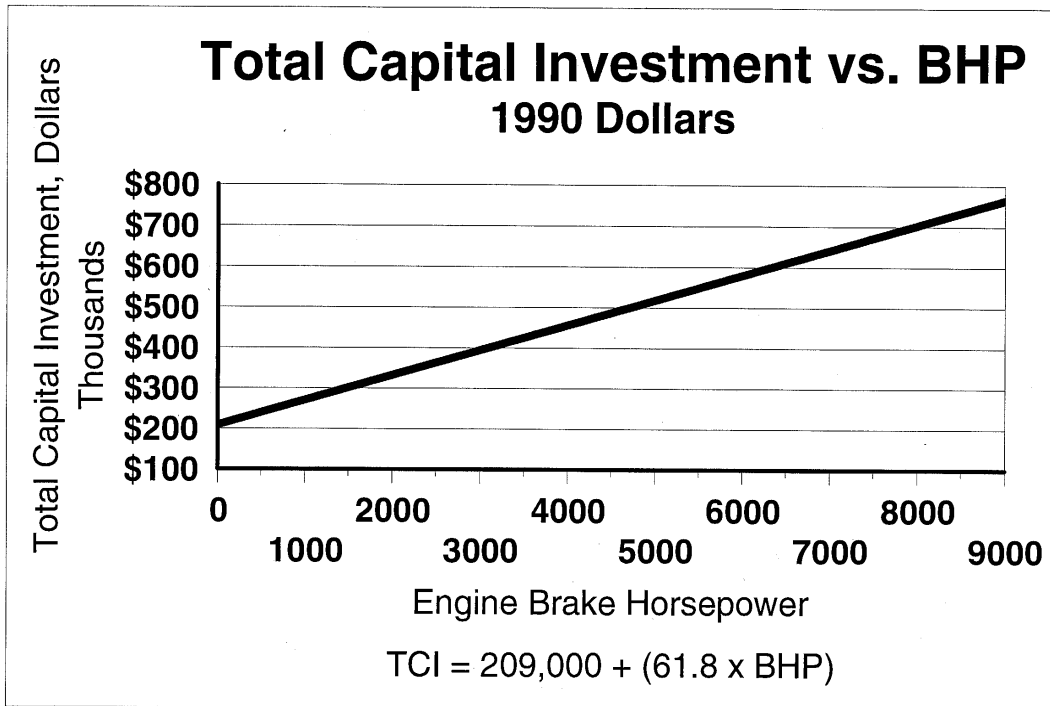


Figure 5-2a. Total capital investment for LEC retrofit (1990 Dollars) versus rated brake horsepower.

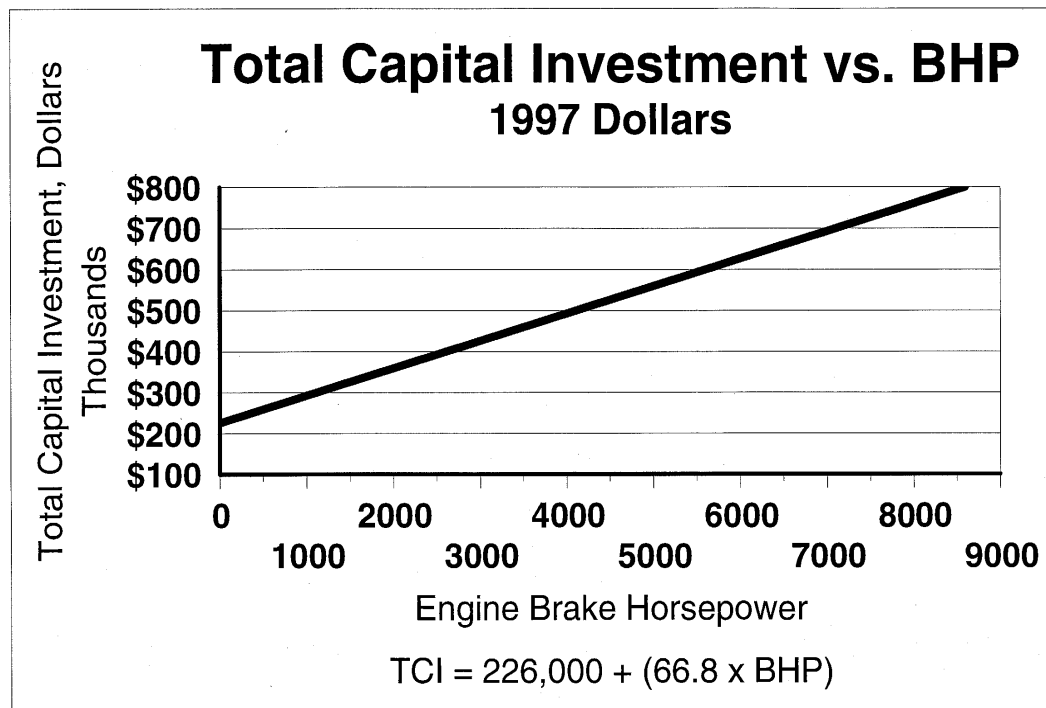


Figure 5-2b. Total capital investment for LEC retrofit (1997 Dollars) versus rated brake horsepower.

increase as a result of the retrofit. In addition to the oxidation catalyst itself, the \$93,000 includes the cost of engineering, structural support, instrumentation, and exhaust piping changes. Of the \$140,000 in in-house expenses, about 70 percent is for the labor required for engineering, construction coordinating, testing, permitting, etc. About 20 percent of the in-house expenses is for construction work (foundations, conduit, electric power) that was outside the scope of the LEC vendor. The remaining 10 percent is for the cost of the permit and other expenses.

Representatives of the company estimated that an LEC retrofit by the original equipment manufacturer (OEM) of a 2,000 bhp engine like the Ingersoll-Rand Model KVS engines at their facilities would cost approximately \$1 million today. This estimate was based on the quote for the Clark engine retrofit discussed above, scaled up to account for the fact that the KVS engines have four more cylinders and would require a much larger turbocharger. In addition, the OEM retrofit would involve replacing the cylinder heads, rather than the use of screw-in precombustion chambers. However, the largest single component of the cost would be the new turbocharger and intercooler. For example, they noted that the current price for the turbochargers on some 5,500 bhp Delaval engines they had retrofitted with LEC is \$350,000 apiece.

The company representatives indicated that LEC vendors typically state that retrofits cost \$200,000 to \$300,000, which includes \$200,000 paid to the vendor and \$100,000 in other costs incurred by the facility. This company has accomplished LEC retrofits at about this cost, but only when all conditions were right, including an existing turbocharger with adequate capacity and use of screw-in precombustion chambers. These representatives indicated that LEC retrofit costs at the levels discussed in the previous paragraphs are more typical because LEC vendors' quotes do not include all the options that the engine operator may feel are necessary. Site-specific situations such as safety concerns, limited room for the turbocharger, out-of-the-ordinary permit conditions, unmanned operation, company procedures, construction schedule restrictions, warranty requirements, more stringent acceptance testing, and so forth can have a great impact on costs. Because the engine operator is liable if the engine fails to meet the applicable NO_x emission limit, the operator needs a good specification and contract to hold the LEC vendor accountable in the event of a violation.^{6, 7, 8}

These costs are well in excess of the costs predicted by Figure 5-2b, which would be about \$290,000 for a 1,000 bhp engine and \$360,000 for a 2,000 bhp engine. The amounts estimated by these company representatives are over twice as much.

There is a large divergence between the information from LEC retrofit vendors and this information from company representatives. One of the recently-retrofitted engines included in the cost information provided by the third-party LEC retrofit vendor is an Ingersoll-Rand Model KVS412, 2,000 bhp engine. The retrofit included replacing the engine's turbocharger and cleaning the intercooler for reuse. The cost of the retrofit (i.e., the amount paid to the vendor) was about \$218,000. Adding \$8,000 for an electronic A/F ratio controller and applying the factors for installation, etc. discussed in Section 5.1.1.2 above would bring the TCI to about \$390,000.

One explanation for the discrepancy between this estimate and the company's estimate of \$1 million for an OEM retrofit was offered by the third-party vendor. This vendor indicated that conventional OEM retrofits have high costs because they involve a nearly complete make-over of the engine. This involves replacement of many engine components in addition to the cylinder heads, including cylinder sleeves, pistons, the exhaust manifold, etc. As an example, the third-party vendor noted that one client had several identical Clark Model TLA-6 2,000 bhp engines retrofitted with LEC. One engine was retrofitted by the OEM at a cost of \$1.1 million. The remaining six engines were retrofitted by the third-party vendor at a cost of \$205,000 each. This vendor also indicated that the cost of some OEM retrofits has come down. In cases where the engine owner does not wish to purchase the full engine make-over, the OEM may offer less extensive modifications. These retrofits may include screw-in precombustion chambers manufactured by a third-party vendor.⁹

The third-party vendor also noted that the cost of an LEC retrofit is very dependent on the particular engine being serviced. Many engines have been upgraded and modernized over time with such improvements as electronic ignition systems. However, others have not, and such engines require these additional upgrades at the time of the LEC retrofit. In some cases, other atypical costs may be incurred, such as foundation improvements to bear the weight of added equipment.¹⁰ Foundation requirements appear to be a factor in the case of the relatively costly Clark Model HSRA retrofit mentioned above. In addition, the cost of an oxidation catalyst is included in the costs provided by the company. It is not appropriate to include this cost in a nationwide cost analysis because it is specific to the Southern California area where the company is located.

In light of the discussion above, the cost analysis in this report was conducted based on the regression curves derived from LEC retrofit vendor data. These cost data represent the actual costs for recent LEC retrofits and are believed to be typical. However, in some cases, costs may be higher due to site-specific and/or engine-specific factors.

5.1.2 Annual Costs

This report closely follows the 1993 ACT document methodology for calculating annual costs, including the following cost elements:

- Maintenance: labor and materials calculated as 10 percent of PEC. (Based on available information, this factor is high for LEC. The factor was retained in the interests of conservatism and consistency with the 1993 ACT document.)
- Overhead: 60 percent of maintenance costs.
- Fuel savings: 1 percent of annual fuel cost, based on the average 1998 cost of natural gas to industrial users. This is consistent with the ACT document and appears conservatively representative. Other information indicates that the effect has ranged from a fuel penalty of 2 or 3 percent to a fuel savings of up to 10 percent.

- Taxes, insurance, and administration: 4 percent of TCI.
- Annual compliance test: \$3,270. (Based on the value of \$2,440 and escalation methodology [5 percent per year] used in the 1993 ACT document.)
- Capital recovery factor: 0.1098. (Based on 15-year equipment life and 7 percent interest rate.)

Annual costs were calculated by summing these cost elements based on 7,000 hours of operation annually. (Capacity utilization affects annual costs only in the fuel credit, which is based on annual operating hours, brake horsepower, and heat rate.) Figures 5-3a and 5-3b show the results in 1990 and 1997 dollars, respectively. See Chapter 2, Tables 2-2a and 2-2b for a summary of annual costs for selected engine sizes in 1990 dollars and 1997 dollars, respectively.

The 1993 ACT document primarily used 8,000 hours of operation in its calculations, but also showed the effect of some different levels of capacity utilization. This report uses 7,000 hours per year based on information obtained for IC engines used in the natural gas transmission and storage industry.

The natural gas transmission and storage industry accounts for a significant portion of the larger SI engines in the United States. A 1994 report prepared for the Gas Research Institute (GRI) states that 7,000 hours per year (80 percent capacity utilization) is representative of engines in natural gas transmission service. That report indicates that engines in natural gas storage service are typically smaller and operate at capacity utilizations in the range of 25 to 40 percent.¹¹

The data base of large IC engines compiled by the Ozone Transport Assessment Group (OTAG) indicates a higher capacity utilization. This data base includes engines in the 22 Eastern States with average daily NO_x emissions of 1 ton or more during the ozone season (May through September).¹² Based on an analysis of the seasonal throughput and operating hours per day, days per week, and weeks per year listed in the data base for these engines, they average about 93 percent capacity utilization during the ozone season. On an annual basis, this corresponds to about 8,150 hours per year.

A data base of IC engines also was compiled for the Industrial Combustion Coordinated Rulemaking (ICCR) effort. This is a nationwide data base. The IC engines in this data base with the Standard Industrial Classification (SIC) code for natural gas transmission and storage (SIC code 4922) average about 6,900 operating hours per year.¹³

One source indicated that capacity utilization might be lower, at least for larger engines. In comments on the final NO_x SIP call, the Interstate Natural Gas Association of America (INGAA) indicated that IC engines with horsepower greater than or equal to 4,000 bhp at natural gas transmission facilities in the OTAG States average less than 25 percent capacity usage during the 2nd and 3rd quarters, which encompass the ozone season. These data are based on a survey of the natural gas industry conducted by the industry.¹⁴

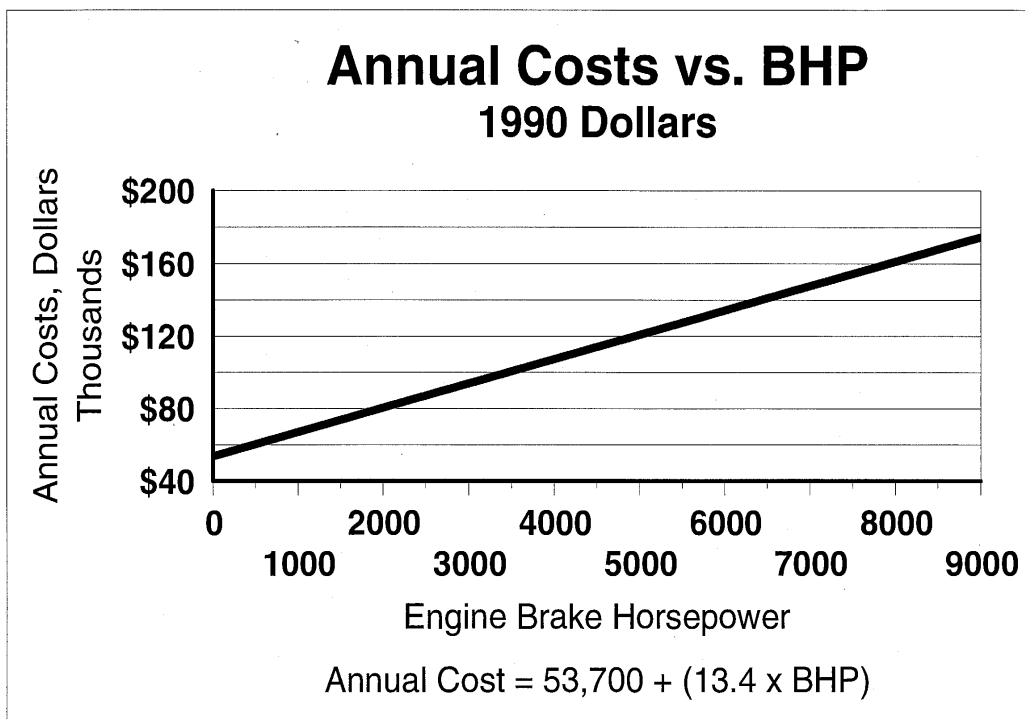


Figure 5-3a. Annual costs for LEC retrofit (1990 Dollars) versus rated brake horsepower.

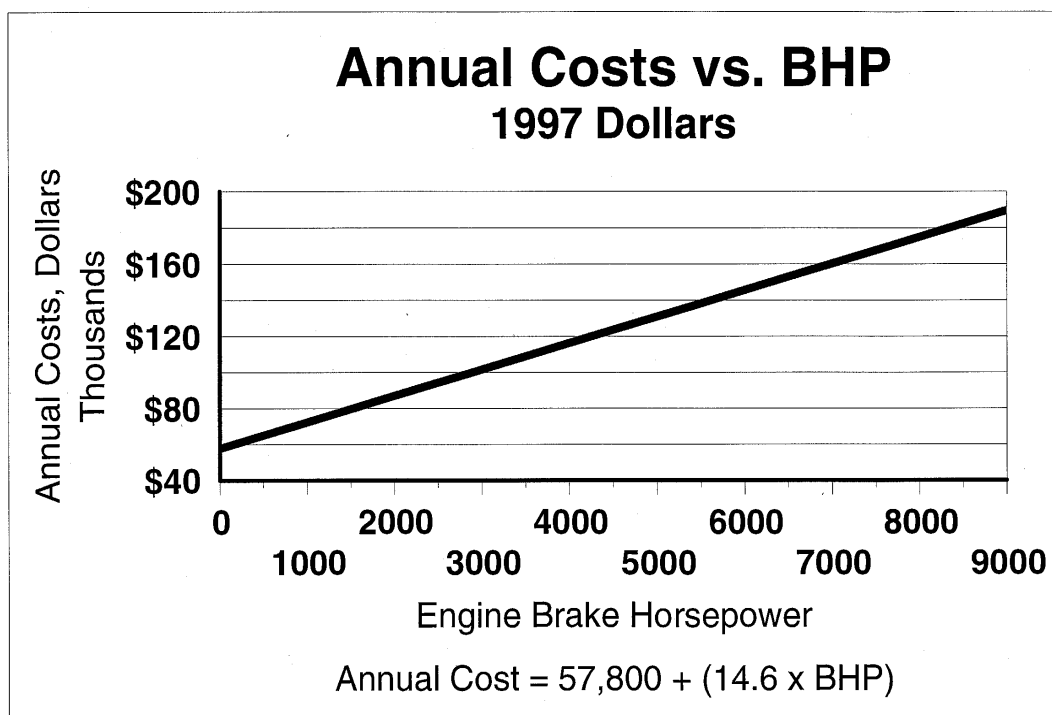


Figure 5-3b. Annual costs for LEC retrofit (1997 Dollars) versus rated brake horsepower.

Based on all this information, 7,000 hours per year is a representative value for IC engines used in the natural gas transmission and storage industry. Because this industry represents a significant fraction of all SI engines likely to come under NO_x regulations, it is reasonable to use this value for the entire population of SI engines, as well.

5.1.3 Cost Effectiveness

This report closely follows the 1993 ACT document methodology for calculating cost effectiveness on an annual basis. In addition, cost effectiveness based only on the ozone season was calculated.

On an annual basis, cost effectiveness is determined for an engine by calculating the tons of NO_x emissions reduced through the use of the control technique, and dividing this quantity into the annual cost. The results of this analysis for lean-burn SI engines appear in Figures 5-4a and 5-4b for 1990 dollars and 1997 dollars, respectively. These figures show cost effectiveness below \$500 per ton of NO_x reduced for all engines larger than 2,000 bhp.

For the ozone season, a similar approach was used. However, in this case the NO_x emission reduction was calculated for the 5 months of the ozone season. This value was divided into the total annual costs to determine cost effectiveness for the ozone season. The entire annual cost was used because LEC technology is integral to the engine and must be operated and maintained throughout the year. Figures 5-5a and 5-5b present the results of this analysis in 1990 dollars and 1997 dollars, respectively. These figures show cost effectiveness below \$1,000 per ton for all engines larger than about 2,000 bhp, falling to \$500 per ton for engines larger than about 5,000 bhp. See Chapter 2, Tables 2-2a and 2-2b for a summary of annual and ozone season cost-effectiveness values for selected engine sizes in 1990 dollars and 1997 dollars, respectively.

The NO_x emission reductions used in the annual cost effectiveness calculations were based on uncontrolled emissions of 16.8 grams per brake horsepower hour (g/bhp-hr), controlled emissions of 2.0 g/bhp-hr, and 7,000 operating hours. For the ozone season cost effectiveness, the NO_x emission reduction was prorated to the 5 months of the ozone season. The rationale for these uncontrolled and controlled emissions values appears in Chapters 3 and 4, respectively. As discussed in Section 5.1.2, this capacity utilization value is believed to be representative based on available information.

Some other sources also have estimated the cost effectiveness of LEC. A 1990 GRI report estimated cost effectiveness at about \$500 to \$700 per ton of NO_x reduced. These calculations included a significant cost savings for improved engine performance (increased power and better fuel efficiency).¹⁵ Another GRI report published in 1994 included LEC cost analyses for three engines of 1,100 bhp, 1,800 bhp, and 2,000 bhp. The cost effectiveness values for these engines were calculated to be about \$1,700 to \$1,800 per ton. These values exceed those of this report's analysis because the GRI report estimated higher capital costs and smaller NO_x emission percent reductions (80 percent). That report was prepared before LEC technology was simplified and improved in the later 1990's.¹⁶

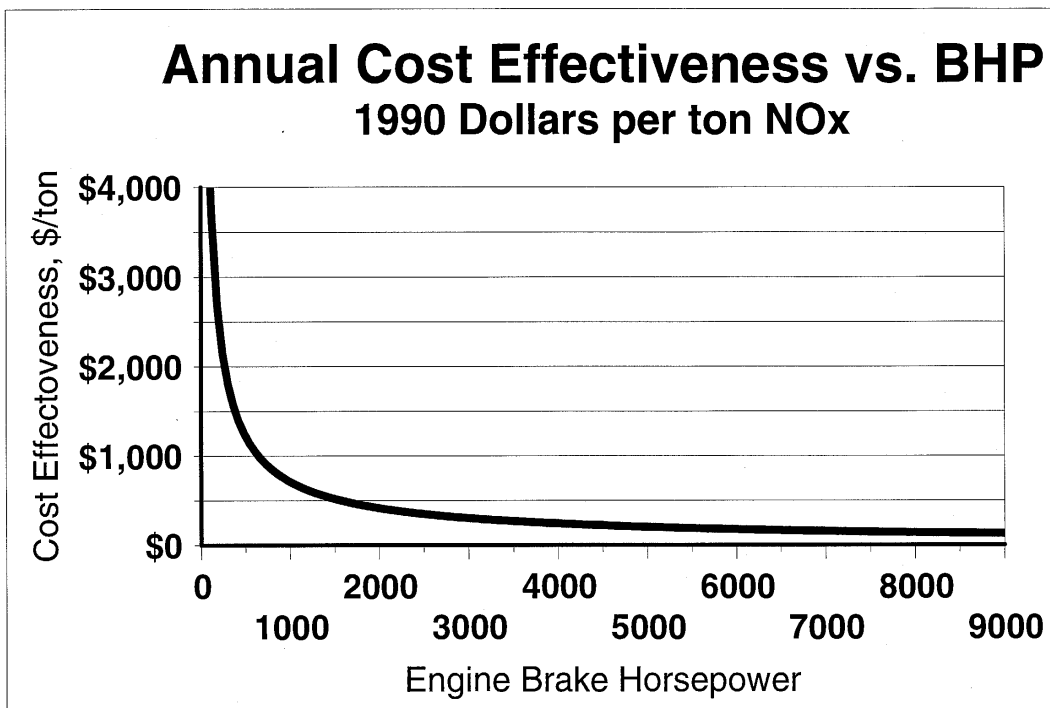


Figure 5-4a. Annual cost effectiveness of LEC retrofit (1990 Dollars) versus rated brake horsepower.

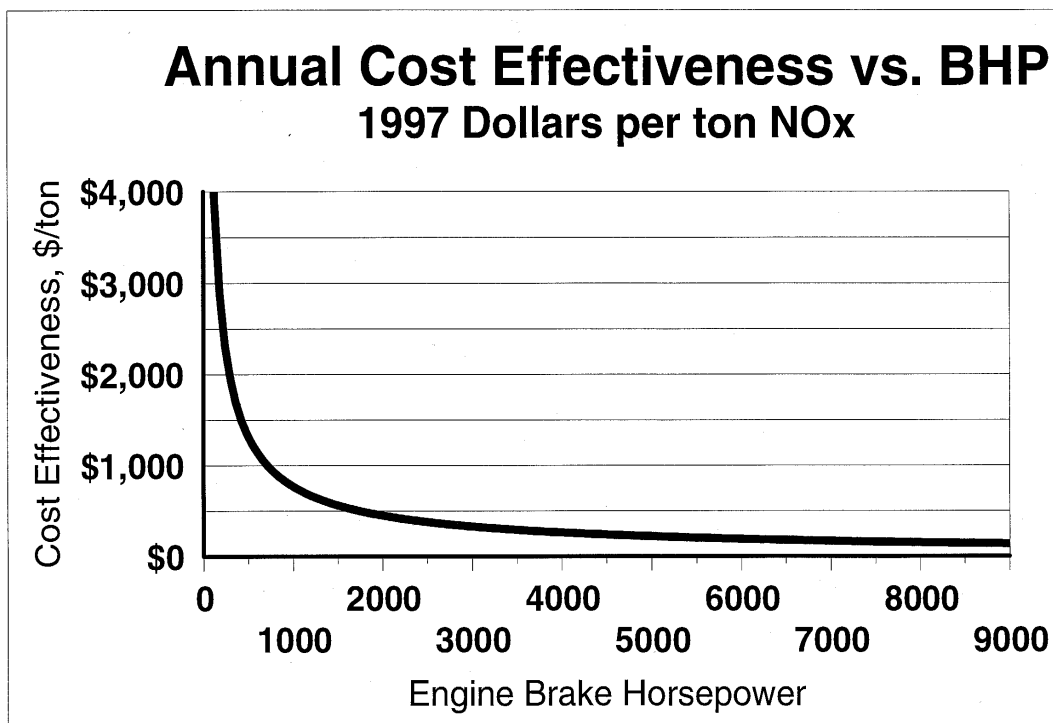


Figure 5-4b. Annual cost effectiveness of LEC retrofit (1997 Dollars) versus rated brake horsepower.

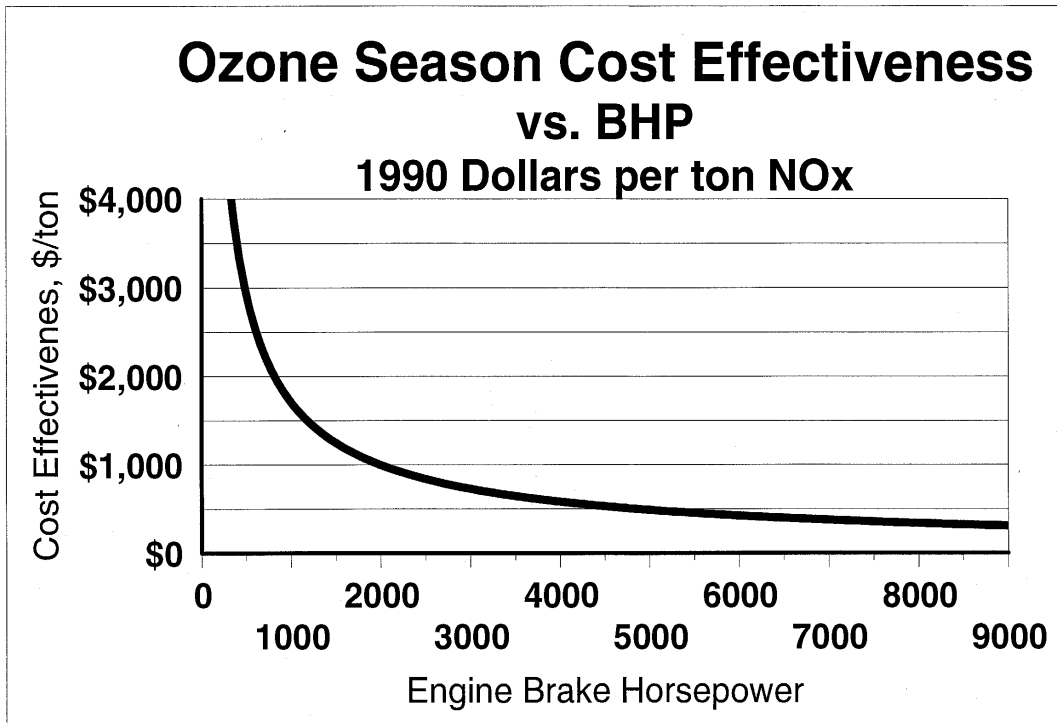


Figure 5-5a. Ozone season cost effectiveness of LEC retrofit (1990 Dollars) versus rated brake horsepower.

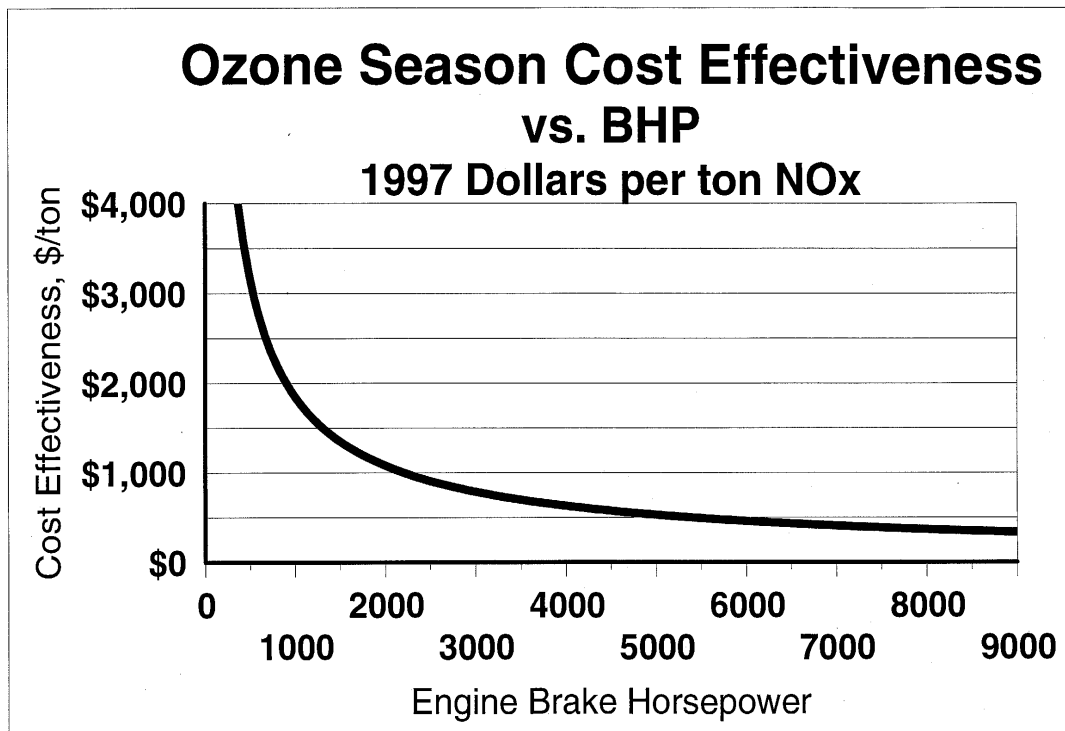


Figure 5-5b. Ozone season cost effectiveness of LEC retrofit (1990 Dollars) versus rated brake horsepower.

A 1997 proposed determination of reasonable available control technology (RACT) and best available retrofit technology (BARCT) prepared by the California Air Resources Board (CARB) also includes some cost effectiveness estimates. This document reproduces findings from a 1991 Santa Barbara County Air Pollution Control District (SBCAPCD) staff paper that indicate that LEC retrofits have a cost effectiveness of \$7,400 per ton for 500 bhp to 1,100 bhp engines. The document also includes recalculated cost effectiveness based on the SBCAPCD data and 1996 LEC vendor prices. The updated cost effectiveness is \$1,300 to \$2,000 per ton for 300 bhp to 500 bhp engines.¹⁷ These figures are higher than this report's analysis because SBCAPCD used a much lower capacity utilization, presumably based on actual data from the engines in the district, and included relatively small engines. The combination of low capacity utilization, smaller engines, and old, higher capital costs resulted in the very high cost effectiveness values in the original SBCAPCD analysis.

Data on LEC cost effectiveness also were received from an engine manufacturer that provides OEM retrofit services. This vendor prepared a curve relating annual cost effectiveness to engine horsepower, much like Figures 5-4a and 5-4b. This curve shows cost effectiveness falling to below \$500 per ton for engines larger than 500 bhp. These estimated costs are lower than those of this report's analysis because of lower capital cost estimates, based largely on lower direct and indirect installation costs.¹⁸

A 2000 report prepared by E. H. Pechan & Associates, Inc. for the U. S. Environmental protection Agency (EPA) estimated annual and ozone season cost effectiveness for 2,000 bhp, 4,000 bhp, and 8,000 bhp engines under a variety of scenarios. In most scenarios, costs were based on the LEC retrofit cost information from an engine manufacturer that was also used for the analysis carried out for this report, although one scenario involved costs from the 1993 ACT document. The other scenarios involved variations in the uncontrolled NO_x emission level, the controlled NO_x emission level, or the capacity utilization. For these scenarios, the average annual cost effectiveness varied between \$168 per ton and \$390 per ton in 1990 dollars. The average ozone season cost effectiveness varied between \$404 per ton and \$936 per ton in 1990 dollars.

Overall, these other cost analyses are not inconsistent with the analysis in this report. When the reasons for the differences in cost effectiveness values are understood, particularly the reduced cost of modern retrofits, these results are reasonable.

5.1.4 Monitoring Costs

Costs for monitoring are not included in the cost analyses above. For information on the cost of a continuous emissions monitoring system (CEMS) for NO_x, see the *U. S. Environmental Protection Agency's Continuous Emission Monitoring System Cost Model Version 3.0* (available at www.epa.gov/ttn/emc/cem.html).

One natural gas storage facility that was visited for this study operates predictive emissions monitoring systems (PEMS) on some engines. A new type of PEMS the company is beginning to install and certify utilizes a pressure sensor in each cylinder. The sensors cost only

\$800 apiece, and are expected to last about 8,000 hours of engine run time. Currently, the company is required to certify the PEMS using the procedures of 40 CFR part 75, subpart E. This requires 800 hours of testing against a certified CEMS or EPA test method, which greatly increases the cost of the PEMS. The company and its PEMS vendor believe that they have demonstrated that good PEMS models can be developed with only a few days of testing.

The company prefers PEMS to CEMS. The equipment is much cheaper, easier to maintain, and more reliable. In addition, the skills required for a PEMS match the skills of the engine personnel. Finally, the PEMS generates data that are useful in determining engine health, unlike a CEMS which only indicates that emissions are high. The company believes that the full cost of a CEMS is greater than indicated by the EPA cost model.¹⁹

5.2 COSTS FOR SCR

As discussed in Section 4.2, SCR technology is undergoing a change. An analysis of the costs of modern SCR systems was not conducted for this study, but a cost analysis was obtained from an SCR vendor.²⁰ The costs are presented below.

The vendor calculated costs and cost effectiveness for two situations involving 2,600 bhp natural gas-fired SI engines: (1) three engines each operated 400 hours per year and (2) one engine operated 2,000 hours per year. For the first case, capital costs were calculated at \$187,000, including catalyst, urea control, injectors, engine map, startup assistance, reagent tank, and installation. For the second case, with just one engine, these costs totaled \$68,000.

Annual costs for the first case totaled \$48,200 based on capital recovery (equipment life of 7 years and 10 percent interest rate) and reagent costs. The emission reduction at 90 percent efficiency totaled 27 tons of NO_x. In combination, this results in a cost effectiveness of about \$1,800 per ton. Based on the same components (except for an equipment life of only 5 years) annual costs for the second case would total \$35,680, the emission reduction would be 45 tons of NO_x, and the cost effectiveness would be under \$800 per ton.

The vendor carried out a similar analysis for a 1,000 bhp diesel engine. For an engine operating 200 hours per year, the cost effectiveness was calculated at almost \$4,000 per ton. For an engine operating 2,000 hours per year, the cost effectiveness dropped to less than \$900 per ton.

These cost and cost effectiveness calculations do not include all the cost elements normally considered by the EPA. For example, no indirect installation costs are included in the capital costs. In addition, the annual costs do not include any operating or maintenance costs.

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United States Environmental Protection Agency	Office of Air Quality Planning and Standards Air Quality Policy Division Research Triangle Park, NC	Publication No. EPA-457/R-00-001 September 2000
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Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

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SOURCE: 69 FR 33506, June 15, 2004, unless otherwise noted.

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WHAT THIS SUBPART COVERS

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§63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

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§63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40 CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

(f) The emergency stationary RICE listed in paragraphs (f)(1) through (3) of this section are not subject to this subpart. The stationary RICE must meet the definition of an emergency stationary RICE in §63.6675, which includes operating according to the provisions specified in §63.6640(f).

(1) Existing residential emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

(2) Existing commercial emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

(3) Existing institutional emergency stationary RICE located at an area source of HAP emissions that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) and that do not operate for the purpose specified in §63.6640(f)(4)(ii).

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008; 78 FR 6700, Jan. 30, 2013]

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§63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of §63.6645(f) and the requirements of §§63.6625(c), 63.6650(g), and 63.6655(c).

These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

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§63.6595 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations, operating limitations and other requirements no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, an existing stationary CI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations, operating limitations, and other requirements no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in §63.6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 78 FR 6701, Jan. 30, 2013]

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EMISSION AND OPERATING LIMITATIONS

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§63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a

stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

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§63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

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§63.6602 What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

[78 FR 6701, Jan. 30, 2013]

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§63.6603 What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart.

(a) If you own or operate an existing stationary RICE located at an area source of HAP emissions, you must comply with the requirements in Table 2d to this subpart and the operating limitations in Table 2b to this subpart that apply to you.

(b) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meets either paragraph (b)(1) or (2) of this section, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. Existing stationary non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP that meet either paragraph (b)(1) or (2) of this section must meet the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart.

(1) The area source is located in an area of Alaska that is not accessible by the Federal Aid Highway System (FAHS).

(2) The stationary RICE is located at an area source that meets paragraphs (b)(2)(i), (ii), and (iii) of this section.

(i) The only connection to the FAHS is through the Alaska Marine Highway System (AMHS), or the stationary RICE operation is within an isolated grid in Alaska that is not connected to the statewide electrical grid referred to as the Alaska Railbelt Grid.

(ii) At least 10 percent of the power generated by the stationary RICE on an annual basis is used for residential purposes.

(iii) The generating capacity of the area source is less than 12 megawatts, or the stationary RICE is used exclusively for backup power for renewable energy.

(c) If you own or operate an existing stationary non-emergency CI RICE with a site rating of more than 300 HP located on an offshore vessel that is an area source of HAP and is a nonroad vehicle that is an Outer Continental Shelf (OCS) source as defined in 40 CFR 55.2, you do not have to meet the numerical CO emission limitations specified in Table 2d of this subpart. You must meet all of the following management practices:

(1) Change oil every 1,000 hours of operation or annually, whichever comes first. Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement.

(2) Inspect and clean air filters every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(3) Inspect fuel filters and belts, if installed, every 750 hours of operation or annually, whichever comes first, and replace as necessary.

(4) Inspect all flexible hoses every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

(d) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and that is subject to an enforceable state or local standard that requires the engine to be replaced no later than June 1, 2018, you may until January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018, choose to comply with the management practices that are shown for stationary non-emergency CI RICE with a site rating of less than or equal to 300 HP in Table 2d of this subpart instead of the applicable emission limitations in Table 2d, operating limitations in Table 2b, and crankcase ventilation system requirements in §63.6625(g). You must comply with the emission limitations in Table 2d and operating limitations in Table 2b that apply for non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018. You must also comply with the crankcase ventilation system requirements in §63.6625(g) by January 1, 2015, or 12 years after the installation date of the engine (whichever is later), but not later than June 1, 2018.

(e) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 3 (Tier 2 for engines above 560 kilowatt (kW)) emission standards in Table 1 of 40 CFR 89.112, you may comply with the requirements under this part by meeting the requirements for Tier 3 engines (Tier 2 for engines above 560 kW) in 40 CFR part 60 subpart IIII instead of the emission limitations and other requirements that would otherwise apply under this part for existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions.

(f) An existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP must meet the definition of remote stationary RICE in §63.6675 on the initial compliance date for the engine, October 19, 2013, in order to be considered a remote stationary RICE under this subpart. Owners and operators of existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that meet the definition of remote stationary RICE in §63.6675 of this subpart as of October 19, 2013 must evaluate the status of their stationary RICE every 12 months. Owners and operators must keep records of the initial and annual evaluation of the status of the engine. If the evaluation indicates that the stationary RICE no longer meets the definition of remote stationary RICE in §63.6675 of this subpart, the owner or operator must comply with all of the requirements for existing non-emergency SI 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at area sources of HAP that are not remote stationary RICE within 1 year of the evaluation.

[75 FR 9675, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6701, Jan. 30, 2013]

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§63.6604 What fuel requirements must I meet if I own or operate a stationary CI RICE?

(a) If you own or operate an existing non-emergency, non-black start CI stationary RICE with a site rating of more than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel.

(b) Beginning January 1, 2015, if you own or operate an existing emergency CI stationary RICE with a site rating of more than 100 brake HP and a displacement of less than 30 liters per cylinder

that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in §63.6640(f)(4)(ii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(c) Beginning January 1, 2015, if you own or operate a new emergency CI stationary RICE with a site rating of more than 500 brake HP and a displacement of less than 30 liters per cylinder located at a major source of HAP that uses diesel fuel and operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii), you must use diesel fuel that meets the requirements in 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to January 1, 2015, may be used until depleted.

(d) Existing CI stationary RICE located in Guam, American Samoa, the Commonwealth of the Northern Mariana Islands, at area sources in areas of Alaska that meet either §63.6603(b)(1) or §63.6603(b)(2), or are on offshore vessels that meet §63.6603(c) are exempt from the requirements of this section.

[78 FR 6702, Jan. 30, 2013]

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GENERAL COMPLIANCE REQUIREMENTS

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§63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations, operating limitations, and other requirements in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

[75 FR 9675, Mar. 3, 2010, as amended at 78 FR 6702, Jan. 30, 2013]

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TESTING AND INITIAL COMPLIANCE REQUIREMENTS

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§63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance test to demonstrate compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial performance test on units for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

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§63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug. 20, 2010]

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§63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

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§63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

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§63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again. The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load for the stationary RICE listed in paragraphs (b)(1) through (4) of this section.

(1) Non-emergency 4SRB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(2) New non-emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP located at a major source of HAP emissions.

(3) New non-emergency 2SLB stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(4) New non-emergency CI stationary RICE with a site rating of greater than 500 brake HP located at a major source of HAP emissions.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour, unless otherwise specified in this subpart.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

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Where:

C_i = concentration of carbon monoxide (CO), total hydrocarbons (THC), or formaldehyde at the control device inlet,

C_o = concentration of CO, THC, or formaldehyde at the control device outlet, and

R = percent reduction of CO, THC, or formaldehyde emissions.

(2) You must normalize the CO, THC, or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2 concentration is measured in lieu of oxygen concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

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Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, $dsf/10^6$ Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, $dsf/10^6$ Btu)

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2 , as follows:

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Where:

X_{CO_2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2 —15 percent O_2 , the defined O_2 correction value, percent.

(iii) Calculate the CO, THC, and formaldehyde gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

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Where:

C_{adj} = Calculated concentration of CO, THC, or formaldehyde adjusted to 15 percent O_2 .

C_d = Measured concentration of CO, THC, or formaldehyde, uncorrected.

X_{CO_2} = CO_2 correction factor, percent.

$\%CO_2$ = Measured CO_2 concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde and you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.*, operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e.g.*, wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the parameters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, the engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, pressure, and humidity during the performance test, and all assumptions that were made to estimate or calculate percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010; 78 FR 6702, Jan. 30, 2013]

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§63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either O₂ or CO₂ according to the requirements in paragraphs (a)(1) through (4) of this section. If you are meeting a requirement to reduce CO emissions, the CEMS must be installed at both the inlet and outlet of the control device. If you are meeting a requirement to limit the concentration of CO, the CEMS must be installed at the outlet of the control device.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in §63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in §63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in §63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO₂ concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (6) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in §63.8(d). As specified in §63.8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other audit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §63.8(c)(1)(ii) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also §63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP emissions;

(6) An existing non-emergency, non-black start stationary RICE located at an area source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis.

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply

with either paragraph (g)(1) or paragraph (2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska that meet either §63.6603(b)(1) or §63.6603(b)(2) do not have to meet the requirements of this paragraph (g). Existing CI engines located on offshore vessels that meet §63.6603(c) do not have to meet the requirements of this paragraph (g).

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when

the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011; 78 FR 6703, Jan. 30, 2013]

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§63.6630 How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate initial compliance with each emission limitation, operating limitation, and other requirement that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.6645.

(d) Non-emergency 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more can demonstrate initial compliance with the formaldehyde emission limit by testing for THC instead of formaldehyde. The testing must be conducted according to the requirements in Table 4 of this subpart. The average reduction of emissions of THC determined from the performance test must be equal to or greater than 30 percent.

(e) The initial compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least three test runs.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O₂ using one of the O₂ measurement methods specified in Table 4 of this subpart. Measurements to determine O₂ concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O₂ emissions simultaneously at the inlet and outlet of the control device.

[69 FR 33506, June 15, 2004, as amended at 78 FR 6704, Jan. 30, 2013]

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CONTINUOUS COMPLIANCE REQUIREMENTS

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§63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

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§63.6640 How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

(a) You must demonstrate continuous compliance with each emission limitation, operating limitation, and other requirements in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during

the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) The annual compliance demonstration required for existing non-emergency 4SLB and 4SRB stationary RICE with a site rating of more than 500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year must be conducted according to the following requirements:

(1) The compliance demonstration must consist of at least one test run.

(2) Each test run must be of at least 15 minute duration, except that each test conducted using the method in appendix A to this subpart must consist of at least one measurement cycle and include at least 2 minutes of test data phase measurement.

(3) If you are demonstrating compliance with the CO concentration or CO percent reduction requirement, you must measure CO emissions using one of the CO measurement methods specified in Table 4 of this subpart, or using appendix A to this subpart.

(4) If you are demonstrating compliance with the THC percent reduction requirement, you must measure THC emissions using Method 25A, reported as propane, of 40 CFR part 60, appendix A.

(5) You must measure O₂ using one of the O₂ measurement methods specified in Table 4 of this subpart. Measurements to determine O₂ concentration must be made at the same time as the measurements for CO or THC concentration.

(6) If you are demonstrating compliance with the CO or THC percent reduction requirement, you must measure CO or THC emissions and O₂ emissions simultaneously at the inlet and outlet of the control device.

(7) If the results of the annual compliance demonstration show that the emissions exceed the levels specified in Table 6 of this subpart, the stationary RICE must be shut down as soon as safely possible, and appropriate corrective action must be taken (e.g., repairs, catalyst cleaning, catalyst replacement). The stationary RICE must be retested within 7 days of being restarted and the emissions must meet the levels specified in Table 6 of this subpart. If the retest shows that the emissions continue to exceed the specified levels, the stationary RICE must again be shut down as soon as safely possible, and the stationary RICE may not operate, except for purposes of startup and testing, until the owner/operator demonstrates through testing that the emissions do not exceed the levels specified in Table 6 of this subpart.

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart: An existing

2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) If you own or operate an emergency stationary RICE, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1) through (4) of this section. In order for the engine to be considered an emergency stationary RICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (4) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (4) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary RICE in emergency situations.

(2) You may operate your emergency stationary RICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraphs (f)(3) and (4) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year.

(ii) Emergency stationary RICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §63.14), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary RICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary RICE located at major sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. The 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(4) Emergency stationary RICE located at area sources of HAP may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraphs (f)(4)(i) and (ii) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) Prior to May 3, 2014, the 50 hours per year for non-emergency situations can be used for peak shaving or non-emergency demand response to generate income for a facility, or to otherwise supply power as part of a financial arrangement with another entity if the engine is operated as part of a peak shaving (load management program) with the local distribution system operator and the power is provided only to the facility itself or to support the local distribution system.

(ii) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator.

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6704, Jan. 30, 2013]

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NOTIFICATIONS, REPORTS, AND RECORDS

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§63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63.9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1).

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to §63.10(d)(2).

(i) If you own or operate an existing non-emergency CI RICE with a site rating of more than 300 HP located at an area source of HAP emissions that is certified to the Tier 1 or Tier 2 emission standards in Table 1 of 40 CFR 89.112 and subject to an enforceable state or local standard requiring engine replacement and you intend to meet management practices rather than emission limits, as specified in §63.6603(d), you must submit a notification by March 3, 2013, stating that you intend to use the provision in §63.6603(d) and identifying the state or local regulation that the engine is subject to.

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010; 78 FR 6705, Jan. 30, 2013]

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§63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports

pursuant to 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in §63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

(h) If you own or operate an emergency stationary RICE with a site rating of more than 100 brake HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in §63.6640(f)(4)(ii), you must submit an annual report according to the requirements in paragraphs (h)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in §63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in §63.6640(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purpose specified in §63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in §63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(viii) If there were no deviations from the fuel requirements in §63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

(ix) If there were deviations from the fuel requirements in §63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in §63.13.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9677, Mar. 3, 2010; 78 FR 6705, Jan. 30, 2013]

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§63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in §63.10(b)(2)(xiv).

(2) Records of the occurrence and duration of each malfunction of operation (*i.e.*, process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep the records listed in paragraphs (b)(1) through (3) of this section.

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in §63.8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) through (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in §63.6640(f)(2)(ii) or (iii) or §63.6640(f)(4)(ii), the owner or operator must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation for these purposes.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 78 FR 6706, Jan. 30, 2013]

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§63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

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OTHER REQUIREMENTS AND INFORMATION

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§63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

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§63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in §63.6600 under §63.6(g).

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in §63.6610(b).

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§63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Alaska Railbelt Grid means the service areas of the six regulated public utilities that extend from Fairbanks to Anchorage and the Kenai Peninsula. These utilities are Golden Valley Electric Association; Chugach Electric Association; Matanuska Electric Association; Homer Electric Association; Anchorage Municipal Light & Power; and the City of Seward Electric System.

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Backup power for renewable energy means an engine that provides backup power to a facility that generates electricity from renewable energy resources, as that term is defined in Alaska Statute 42.45.045(l)(5) (incorporated by reference, see §63.14).

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq.*, as amended by Public Law 101-549, 104 Stat. 2399).

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas: After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities

or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless of whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by §63.6(e)(1)(i).

Diesel engine means any stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (e.g. biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO₂.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary RICE must comply with the requirements specified in §63.6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in §63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

(1) The stationary RICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(2) The stationary RICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in §63.6640(f).

(3) The stationary RICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in §63.6640(f)(2)(ii) or (iii) and §63.6640(f)(4)(i) or (ii).

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Glycol dehydration unit means a device in which a liquid glycol (including, but not limited to, ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber). The glycol contacts and absorbs water vapor and other gas stream constituents from the natural gas and becomes "rich" glycol. This glycol is then regenerated in the glycol dehydration unit reboiler. The "lean" glycol is then recycled.

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO₂.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated.

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_x) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_x, CO, and volatile organic compounds (VOC) into CO₂, nitrogen, and water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.*, remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storage source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment located at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percent.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in §63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to §63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to §63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8 .

Remote stationary RICE means stationary RICE meeting any of the following criteria:

(1) Stationary RICE located in an offshore area that is beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

(2) Stationary RICE located on a pipeline segment that meets both of the criteria in paragraphs (2)(i) and (ii) of this definition.

(i) A pipeline segment with 10 or fewer buildings intended for human occupancy and no buildings with four or more stories within 220 yards (200 meters) on either side of the centerline of any continuous 1-mile (1.6 kilometers) length of pipeline. Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy.

(ii) The pipeline segment does not lie within 100 yards (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. The days and weeks need not be consecutive. The building or area is considered occupied for a full day if it is occupied for any portion of the day.

(iii) For purposes of this paragraph (2), the term pipeline segment means all parts of those physical facilities through which gas moves in transportation, including but not limited to pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. Stationary RICE located within 50 yards (46 meters) of the pipeline segment providing power for equipment on a pipeline segment are part of the pipeline segment. Transportation of gas means the gathering, transmission, or distribution of gas by pipeline, or the storage of gas. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

(3) Stationary RICE that are not located on gas pipelines and that have 5 or fewer buildings intended for human occupancy and no buildings with four or more stories within a 0.25 mile radius around the engine. A building is intended for human occupancy if its primary use is for a purpose involving the presence of humans.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_x (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart P of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash

emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011; 78 FR 6706, Jan. 30, 2013]

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Table 1a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. ¹
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O ₂	

¹ Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9679, Mar. 3, 2010, as amended at 75 FR 51592, Aug. 20, 2010]

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Table 1b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using NSCR; or existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O ₂ and using NSCR;	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F. ¹
2. existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or	Comply with any operating limitations approved by the Administrator.
existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O ₂ and not using NSCR.	

¹Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6706, Jan. 30, 2013]

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Table 2a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at 15 percent O ₂ . If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O ₂ until June 15, 2007	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. ¹
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O ₂	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O ₂	

¹Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

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Table 2b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP

As stated in §§63.6600, 63.6601, 63.6603, 63.6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; and existing CI stationary RICE >500 HP:

For each . . .	You must meet the following operating limitation, except during periods of startup . . .
1. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and using an oxidation catalyst; and New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and using an oxidation catalyst.	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.¹
2. Existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst that was measured during the initial performance test; and
	b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.¹
3. New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions complying with the requirement to reduce CO emissions and not using an oxidation catalyst; and	Comply with any operating limitations approved by the Administrator.
New and reconstructed 2SLB and CI stationary RICE >500 HP located at a major source of HAP emissions and new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source	

of HAP emissions complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; and	
existing CI stationary RICE >500 HP complying with the requirement to limit or reduce the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst.	

¹Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(f) for a different temperature range.

[78 FR 6707, Jan. 30, 2013]

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Table 2c to Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6602, and 63.6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE ¹	a. Change oil and filter every 500 hours of operation or annually, whichever comes first. ² b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. ³	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply. ³

2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first. ² b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. ³	
3. Non-Emergency, non-black start CI stationary RICE $100 \leq \text{HP} \leq 300$ HP	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O ₂ .	
4. Non-Emergency, non-black start CI stationary RICE $300 < \text{HP} \leq 500$	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O ₂ ; or b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O ₂ ; or b. Reduce CO emissions by 70 percent or more.	
6. Emergency stationary SI RICE and black start stationary SI RICE. ¹	a. Change oil and filter every 500 hours of operation or annually, whichever comes first; ² b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of	

	operation or annually, whichever comes first, and replace as necessary. ³	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first; ² b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary. ³	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first; ² b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary;	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary. ³	
9. Non-emergency, non-black start 2SLB stationary RICE $100 \leq \text{HP} \leq 500$	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O ₂ .	
10. Non-emergency, non-black start 4SLB stationary RICE $100 \leq \text{HP} \leq 500$	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O ₂ .	

11. Non-emergency, non-black start 4SRB stationary RICE 100≤HP≤500	Limit concentration of formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O ₂ .	
12. Non-emergency, non-black start stationary RICE 100≤HP≤500 which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O ₂ .	

¹If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

²Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2c of this subpart.

³Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[78 FR 6708, Jan. 30, 2013, as amended at 78 FR 14457, Mar. 6, 2013]

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Table 2d to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of	Minimize the engine's time spent at idle and minimize the

	operation or annually, whichever comes first;¹ b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O ₂ ; or	
	b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O ₂ ; or	
	b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE. ²	a. Change oil and filter every 500 hours of operation or annually, whichever comes first; ¹	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 500 hours	

	of operation or annually, whichever comes first, and replace as necessary.	
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate 24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year. ²	a. Change oil and filter every 500 hours of operation or annually, whichever comes first; ¹ ; b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first; ¹	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first; ¹	
	b. Inspect spark plugs every 1,440 hours of	

	operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start 4SLB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first; ¹	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
9. Non-emergency, non-black start 4SLB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install an oxidation catalyst to reduce HAP emissions from the stationary RICE.	
10. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first; ¹	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	

	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
11. Non-emergency, non-black start 4SRB remote stationary RICE >500 HP	a. Change oil and filter every 2,160 hours of operation or annually, whichever comes first; ¹	
	b. Inspect spark plugs every 2,160 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 2,160 hours of operation or annually, whichever comes first, and replace as necessary.	
12. Non-emergency, non-black start 4SRB stationary RICE >500 HP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Install NSCR to reduce HAP emissions from the stationary RICE.	
13. Non-emergency, non-black start stationary RICE which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first; ¹ b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first, and replace as necessary; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

¹Sources have the option to utilize an oil analysis program as described in §63.6625(i) or (j) in order to extend the specified oil change requirement in Table 2d of this subpart.

²If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated. Sources must report any failure to perform the management practice on the schedule required and the federal, state or local law under which the risk was deemed unacceptable.

[78 FR 6709, Jan. 30, 2013]

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Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

As stated in §§63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE >500 HP located at major sources; new or reconstructed 4SLB stationary RICE ≥250 HP located at major sources; and new or reconstructed CI stationary RICE >500 HP located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually. ¹
2. 4SRB stationary RICE ≥5,000 HP located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually. ¹
3. Stationary RICE >500 HP located at major sources and new or reconstructed 4SLB stationary RICE 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually. ¹
4. Existing non-emergency, non-black start CI stationary RICE >500 HP that are not limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 3 years, whichever comes first.

5. Existing non-emergency, non-black start CI stationary RICE >500 HP that are limited use stationary RICE	Limit or reduce CO emissions and not using a CEMS	Conduct subsequent performance tests every 8,760 hours or 5 years, whichever comes first.
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¹After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[78 FR 6711, Jan. 30, 2013]

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Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§63.6610, 63.6611, 63.6620, and 63.6640, you must comply with the following requirements for performance tests for stationary RICE:

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. reduce CO emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For CO and O ₂ measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter <i>and</i> the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-

				point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure the O ₂ at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005) ^a ^c (heated probe not necessary)	(b) Measurements to determine O ₂ must be made at the same time as the measurements for CO concentration.
		iii. Measure the CO at the inlet and the outlet of the control device	(1) ASTM D6522-00 (Reapproved 2005) ^{a b c} (heated probe not necessary) or Method 10 of 40 CFR part 60, appendix A-4	(c) The CO concentration must be at 15 percent O ₂ , dry basis.
2. 4SRB stationary RICE	a. reduce formaldehyde emissions	i. Select the sampling port location and the number/location of traverse points at the inlet and outlet of the control device; and		(a) For formaldehyde, O ₂ , and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter <i>and</i> the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at '3-point

				long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A.
		ii. Measure O ₂ at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005) ^a (heated probe not necessary)	(a) Measurements to determine O ₂ concentration must be made at the same time as the measurements for formaldehyde or THC concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A-3, or Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 ^a	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde or THC concentration.
		iv. If demonstrating compliance with the formaldehyde percent reduction requirement, measure formaldehyde at the inlet and the outlet of the control device	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03 ^a , provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O ₂ , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. If demonstrating compliance with the THC percent reduction requirement, measure THC at the inlet and the outlet of the control device	(1) Method 25A, reported as propane, of 40 CFR part 60, appendix A-7	(a) THC concentration must be at 15 percent O ₂ , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

3. Stationary RICE	a. limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary RICE; and		(a) For formaldehyde, CO, O ₂ , and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter <i>and</i> the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A. If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O ₂ concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A-2, or ASTM Method D6522-00 (Reapproved 2005) ^a (heated probe not necessary)	(a) Measurements to determine O ₂ concentration must be made at the same time and location as the measurements for formaldehyde or CO concentration.
		iii. Measure moisture content of the station-ary RICE exhaust at the	(1) Method 4 of 40 CFR part 60, appendix A-3, or Method 320 of 40	(a) Measurements to determine moisture content must be made at the same time and

		sampling port location; and	CFR part 63, appendix A, or ASTM D 6348-03 ^a	location as the measurements for formaldehyde or CO concentration.
		iv. Measure formalde-hyde at the exhaust of the station-ary RICE; or	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348-03 ^a , provided in ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O ₂ , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. measure CO at the exhaust of the station-ary RICE	(1) Method 10 of 40 CFR part 60, appendix A-4, ASTM Method D6522-00 (2005) ^{a c} , Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03 ^a	(a) CO concentration must be at 15 percent O ₂ , dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

^aYou may also use Methods 3A and 10 as options to ASTM-D6522-00 (2005). You may obtain a copy of ASTM-D6522-00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

^bYou may obtain a copy of ASTM-D6348-03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428-2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[79 FR 11290, Feb. 27, 2014]

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Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements

As stated in §§63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
4. Non-emergency stationary CI RICE >500 HP located at a major	a. Limit the concentration of CO,	i. The average CO concentration determined from the initial

source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	and not using oxidation catalyst	performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O ₂ or CO ₂ at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP located at an area source of HAP	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O ₂ or CO ₂ at the outlet of the oxidation catalyst according to the requirements in §63.6625(a); and
		ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of CO calculated using §63.6620 is less than or equal to the CO emission limitation. The initial test comprises

		the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction, or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction or the average reduction of emissions of THC determined from the initial performance test is equal to or greater than 30 percent; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.

9. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE $250 \leq \text{HP} \leq 500$ located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O₂, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE $250 \leq \text{HP} \leq 500$ located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O₂, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
11. Existing non-emergency stationary RICE $100 \leq \text{HP} \leq 500$ located at a major source of HAP, and existing non-emergency stationary CI RICE $300 < \text{HP} \leq 500$ located at an area source of HAP	a. Reduce CO emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
12. Existing non-emergency stationary RICE $100 \leq \text{HP} \leq 500$ located at a major source of HAP, and existing non-emergency stationary CI RICE $300 < \text{HP} \leq 500$ located at an area source of HAP	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O₂, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.
13. Existing non-emergency 4SLB stationary RICE >500 HP located at	a. Install an oxidation catalyst	i. You have conducted an initial compliance demonstration as

an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year		specified in §63.6630(e) to show that the average reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O ₂ ;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1350 °F.
14. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. You have conducted an initial compliance demonstration as specified in §63.6630(e) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O ₂ , or the average reduction of emissions of THC is 30 percent or more;
		ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b), or you have installed equipment to automatically shut down the engine if the catalyst inlet temperature exceeds 1250 °F.

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Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements

As stated in §63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved ^a ; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and not using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved ^a ; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	i. Collecting the monitoring data according to §63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to §63.6620;

of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, and existing non-emergency stationary CI RICE >500 HP		and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and
		iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		iv. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.

6. Non-emergency 4SRB stationary RICE with a brake HP $\geq 5,000$ located at a major source of HAP	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved, or to demonstrate that the average reduction of emissions of THC determined from the performance test is equal to or greater than 30 percent. ^a
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE $250 \leq \text{HP} \leq 500$ located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit ^a ; and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE $250 \leq \text{HP} \leq 500$ located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit ^a ; and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating

		parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤ 500 HP located at a major source of HAP, existing non-emergency stationary RICE < 100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤ 300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency stationary SI RICE located at an area source of HAP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, existing non-emergency 4SLB and 4SRB stationary RICE ≤ 500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE > 500 HP located at an area source of HAP that operate 24 hours or less per calendar year, and existing non-emergency 4SLB and 4SRB stationary RICE > 500 HP located at an area source of HAP that are remote stationary RICE	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.
10. Existing stationary CI RICE > 500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and

		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE	a. Reduce CO emissions, or limit the concentration of CO in the stationary RICE exhaust, and not using oxidation catalyst	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that

		your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and not using an oxidation catalyst	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
14. Existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are not	a. Install an oxidation catalyst	i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average

remote stationary RICE and that are operated more than 24 hours per calendar year		reduction of emissions of CO is 93 percent or more, or the average CO concentration is less than or equal to 47 ppmvd at 15 percent O₂; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than 450 °F and less than or equal to 1350 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1350 °F.
15. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that are operated more than 24 hours per calendar year	a. Install NSCR	i. Conducting annual compliance demonstrations as specified in §63.6640(c) to show that the average reduction of emissions of CO is 75 percent or more, the average CO concentration is less than or equal to 270 ppmvd at 15 percent O₂, or the average reduction of emissions of THC is 30 percent or more; and either ii. Collecting the catalyst inlet temperature data according to §63.6625(b), reducing these data to 4-hour rolling averages; and maintaining the 4-hour rolling averages within the limitation of greater than or equal to 750 °F and less than or equal to 1250 °F for the catalyst inlet temperature; or iii. Immediately shutting down the engine if the catalyst inlet temperature exceeds 1250 °F.

^aAfter you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

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Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in §63.6650, you must comply with the following requirements for reports:

For each . . .	You must submit a . . .	The report must contain . . .	You must submit the report . . .
1. Existing non-emergency, non-black start stationary RICE $100 \leq \text{HP} \leq 500$ located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE $250 \leq \text{HP} \leq 500$ located at a major source of HAP	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or	i. Semiannually according to the requirements in §63.6650(b)(1)-(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in §63.6650(b)(6)-(9) for engines that are limited use stationary RICE subject to numerical emission limitations.
		b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in §63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7),	i. Semiannually according to the requirements in §63.6650(b).

		the information in §63.6650(e); or	
		c. If you had a malfunction during the reporting period, the information in §63.6650(c)(4).	i. Semiannually according to the requirements in §63.6650(b).
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and	i. Annually, according to the requirements in §63.6650.
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and	i. See item 2.a.i.
		c. Any problems or errors suspected with the meters.	i. See item 2.a.i.
3. Existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that are not remote stationary RICE and that operate more than 24 hours per calendar year	Compliance report	a. The results of the annual compliance demonstration, if conducted during the reporting period.	i. Semiannually according to the requirements in §63.6650(b)(1)-(5).
4. Emergency stationary RICE that operate or are contractually obligated to be available for more than 15 hours per year for the purposes specified in §63.6640(f)(2)(ii) and (iii) or that operate for the purposes specified in §63.6640(f)(4)(ii)	Report	a. The information in §63.6650(h)(1)	i. annually according to the requirements in §63.6650(h)(2)-(3).

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Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ.

As stated in §63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.1	General applicability of the General Provisions	Yes.	
§63.2	Definitions	Yes	Additional terms defined in §63.6675.
§63.3	Units and abbreviations	Yes.	
§63.4	Prohibited activities and circumvention	Yes.	
§63.5	Construction and reconstruction	Yes.	
§63.6(a)	Applicability	Yes.	
§63.6(b)(1)-(4)	Compliance dates for new and reconstructed sources	Yes.	
§63.6(b)(5)	Notification	Yes.	
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes.	
§63.6(c)(1)-(2)	Compliance dates for existing sources	Yes.	
§63.6(c)(3)-(4)	[Reserved]		
§63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes.	
§63.6(d)	[Reserved]		
§63.6(e)	Operation and maintenance	No.	
§63.6(f)(1)	Applicability of standards	No.	

§63.6(f)(2)	Methods for determining compliance	Yes.	
§63.6(f)(3)	Finding of compliance	Yes.	
§63.6(g)(1)-(3)	Use of alternate standard	Yes.	
§63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§63.6(i)	Compliance extension procedures and criteria	Yes.	
§63.6(j)	Presidential compliance exemption	Yes.	
§63.7(a)(1)-(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§63.6610, 63.6611, and 63.6612.
§63.7(a)(3)	CAA section 114 authority	Yes.	
§63.7(b)(1)	Notification of performance test	Yes	Except that §63.7(b)(1) only applies as specified in §63.6645.
§63.7(b)(2)	Notification of rescheduling	Yes	Except that §63.7(b)(2) only applies as specified in §63.6645.
§63.7(c)	Quality assurance/test plan	Yes	Except that §63.7(c) only applies as specified in §63.6645.
§63.7(d)	Testing facilities	Yes.	
§63.7(e)(1)	Conditions for conducting performance tests	No.	Subpart ZZZZ specifies conditions for conducting performance tests at §63.6620.
§63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at §63.6620.
§63.7(e)(3)	Test run duration	Yes.	
§63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes.	

§63.7(f)	Alternative test method provisions	Yes.	
§63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes.	
§63.7(h)	Waiver of tests	Yes.	
§63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at §63.6625.
§63.8(a)(2)	Performance specifications	Yes.	
§63.8(a)(3)	[Reserved]		
§63.8(a)(4)	Monitoring for control devices	No.	
§63.8(b)(1)	Monitoring	Yes.	
§63.8(b)(2)-(3)	Multiple effluents and multiple monitoring systems	Yes.	
§63.8(c)(1)	Monitoring system operation and maintenance	Yes.	
§63.8(c)(1)(i)	Routine and predictable SSM	No	
§63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes.	
§63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	No	
§63.8(c)(2)-(3)	Monitoring system installation	Yes.	
§63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§63.8(c)(6)-(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§63.8(d)	CMS quality control	Yes.	
§63.8(e)	CMS performance evaluation	Yes	Except for §63.8(e)(5)(ii), which applies to COMS.
		Except that §63.8(e) only applies as	

		specified in §63.6645.	
§63.8(f)(1)-(5)	Alternative monitoring method	Yes	Except that §63.8(f)(4) only applies as specified in §63.6645.
§63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that §63.8(f)(6) only applies as specified in §63.6645.
§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for demonstrating compliance are specified at §§63.6635 and 63.6640.
§63.9(a)	Applicability and State delegation of notification requirements	Yes.	
§63.9(b)(1)-(5)	Initial notifications	Yes	Except that §63.9(b)(3) is reserved.
		Except that §63.9(b) only applies as specified in §63.6645.	
§63.9(c)	Request for compliance extension	Yes	Except that §63.9(c) only applies as specified in §63.6645.
§63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that §63.9(d) only applies as specified in §63.6645.
§63.9(e)	Notification of performance test	Yes	Except that §63.9(e) only applies as specified in §63.6645.
§63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes	Except that §63.9(g) only applies as specified in §63.6645.

§63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use.
		Except that §63.9(g) only applies as specified in §63.6645.	
§63.9(h)(1)-(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.
			Except that §63.9(h) only applies as specified in §63.6645.
§63.9(i)	Adjustment of submittal deadlines	Yes.	
§63.9(j)	Change in previous information	Yes.	
§63.10(a)	Administrative provisions for recordkeeping/reporting	Yes.	
§63.10(b)(1)	Record retention	Yes	Except that the most recent 2 years of data do not have to be retained on site.
§63.10(b)(2)(i)-(v)	Records related to SSM	No.	
§63.10(b)(2)(vi)-(xi)	Records	Yes.	
§63.10(b)(2)(xii)	Record when under waiver	Yes.	
§63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§63.10(b)(3)	Records of applicability determination	Yes.	

§63.10(c)	Additional records for sources using CEMS	Yes	Except that §63.10(c)(2)-(4) and (9) are reserved.
§63.10(d)(1)	General reporting requirements	Yes.	
§63.10(d)(2)	Report of performance test results	Yes.	
§63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.10(d)(4)	Progress reports	Yes.	
§63.10(d)(5)	Startup, shutdown, and malfunction reports	No.	
§63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§63.10(e)(3)	Excess emission and parameter exceedances reports	Yes.	Except that §63.10(e)(3)(i) (C) is reserved.
§63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§63.11	Flares	No.	
§63.12	State authority and delegations	Yes.	
§63.13	Addresses	Yes.	
§63.14	Incorporation by reference	Yes.	
§63.15	Availability of information	Yes.	

[75 FR 9688, Mar. 3, 2010, as amended at 78 FR 6720, Jan. 30, 2013]

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Appendix A to Subpart ZZZZ of Part 63—Protocol for Using an Electrochemical Analyzer to Determine Oxygen and Carbon Monoxide Concentrations From Certain Engines

1.0 SCOPE AND APPLICATION. WHAT IS THIS PROTOCOL?

This protocol is a procedure for using portable electrochemical (EC) cells for measuring carbon monoxide (CO) and oxygen (O₂) concentrations in controlled and uncontrolled emissions from existing stationary 4-stroke lean burn and 4-stroke rich burn reciprocating internal combustion engines as specified in the applicable rule.

1.1 Analytes. What does this protocol determine?

This protocol measures the engine exhaust gas concentrations of carbon monoxide (CO) and oxygen (O₂).

Analyte	CAS No.	Sensitivity
Carbon monoxide (CO)	630-08-0	Minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.
Oxygen (O ₂)	7782-44-7	

1.2 Applicability. When is this protocol acceptable?

This protocol is applicable to 40 CFR part 63, subpart ZZZZ. Because of inherent cross sensitivities of EC cells, you must not apply this protocol to other emissions sources without specific instruction to that effect.

1.3 Data Quality Objectives. How good must my collected data be?

Refer to Section 13 to verify and document acceptable analyzer performance.

1.4 Range. What is the targeted analytical range for this protocol?

The measurement system and EC cell design(s) conforming to this protocol will determine the analytical range for each gas component. The nominal ranges are defined by choosing up-scale calibration gas concentrations near the maximum anticipated flue gas concentrations for CO and O₂, or no more than twice the permitted CO level.

1.5 Sensitivity. What minimum detectable limit will this protocol yield for a particular gas component?

The minimum detectable limit depends on the nominal range and resolution of the specific EC cell used, and the signal to noise ratio of the measurement system. The minimum detectable limit should be 2 percent of the nominal range or 1 ppm, whichever is less restrictive.

2.0 SUMMARY OF PROTOCOL

In this protocol, a gas sample is extracted from an engine exhaust system and then conveyed to a portable EC analyzer for measurement of CO and O₂ gas concentrations. This method provides measurement system performance specifications and sampling protocols to ensure reliable data. You may use additions to, or modifications of vendor supplied measurement systems (e.g., heated or unheated sample lines, thermocouples, flow meters, selective gas scrubbers, etc.) to meet the design specifications of this protocol. Do not make changes to the measurement system from the as-verified configuration (Section 3.12).

3.0 DEFINITIONS

3.1 Measurement System. The total equipment required for the measurement of CO and O₂ concentrations. The measurement system consists of the following major subsystems:

3.1.1 Data Recorder. A strip chart recorder, computer or digital recorder for logging measurement data from the analyzer output. You may record measurement data from the digital data display manually or electronically.

3.1.2 Electrochemical (EC) Cell. A device, similar to a fuel cell, used to sense the presence of a specific analyte and generate an electrical current output proportional to the analyte concentration.

3.1.3 Interference Gas Scrubber. A device used to remove or neutralize chemical compounds that may interfere with the selective operation of an EC cell.

3.1.4 Moisture Removal System. Any device used to reduce the concentration of moisture in the sample stream so as to protect the EC cells from the damaging effects of condensation and to minimize errors in measurements caused by the scrubbing of soluble gases.

3.1.5 Sample Interface. The portion of the system used for one or more of the following: sample acquisition; sample transport; sample conditioning or protection of the EC cell from any degrading effects of the engine exhaust effluent; removal of particulate matter and condensed moisture.

3.2 Nominal Range. The range of analyte concentrations over which each EC cell is operated (normally 25 percent to 150 percent of up-scale calibration gas value). Several nominal ranges can be used for any given cell so long as the calibration and repeatability checks for that range remain within specifications.

3.3 Calibration Gas. A vendor certified concentration of a specific analyte in an appropriate balance gas.

3.4 Zero Calibration Error. The analyte concentration output exhibited by the EC cell in response to zero-level calibration gas.

3.5 Up-Scale Calibration Error. The mean of the difference between the analyte concentration exhibited by the EC cell and the certified concentration of the up-scale calibration gas.

3.6 Interference Check. A procedure for quantifying analytical interference from components in the engine exhaust gas other than the targeted analytes.

3.7 Repeatability Check. A protocol for demonstrating that an EC cell operated over a given nominal analyte concentration range provides a stable and consistent response and is not significantly affected by repeated exposure to that gas.

3.8 Sample Flow Rate. The flow rate of the gas sample as it passes through the EC cell. In some situations, EC cells can experience drift with changes in flow rate. The flow rate must be monitored and documented during all phases of a sampling run.

3.9 Sampling Run. A timed three-phase event whereby an EC cell's response rises and plateaus in a sample conditioning phase, remains relatively constant during a measurement data phase, then declines during a refresh phase. The sample conditioning phase exposes the EC cell to

the gas sample for a length of time sufficient to reach a constant response. The measurement data phase is the time interval during which gas sample measurements can be made that meet the acceptance criteria of this protocol. The refresh phase then purges the EC cells with CO-free air. The refresh phase replenishes requisite O₂ and moisture in the electrolyte reserve and provides a mechanism to de-gas or desorb any interference gas scrubbers or filters so as to enable a stable CO EC cell response. There are four primary types of sampling runs: pre- sampling calibrations; stack gas sampling; post-sampling calibration checks; and measurement system repeatability checks. Stack gas sampling runs can be chained together for extended evaluations, providing all other procedural specifications are met.

3.10 Sampling Day. A time not to exceed twelve hours from the time of the pre-sampling calibration to the post-sampling calibration check. During this time, stack gas sampling runs can be repeated without repeated recalibrations, providing all other sampling specifications have been met.

3.11 Pre-Sampling Calibration/Post-Sampling Calibration Check. The protocols executed at the beginning and end of each sampling day to bracket measurement readings with controlled performance checks.

3.12 Performance-Established Configuration. The EC cell and sampling system configuration that existed at the time that it initially met the performance requirements of this protocol.

4.0 INTERFERENCES.

When present in sufficient concentrations, NO and NO₂ are two gas species that have been reported to interfere with CO concentration measurements. In the likelihood of this occurrence, it is the protocol user's responsibility to employ and properly maintain an appropriate CO EC cell filter or scrubber for removal of these gases, as described in Section 6.2.12.

5.0 SAFETY. [RESERVED]

6.0 EQUIPMENT AND SUPPLIES.

6.1 What equipment do I need for the measurement system?

The system must maintain the gas sample at conditions that will prevent moisture condensation in the sample transport lines, both before and as the sample gas contacts the EC cells. The essential components of the measurement system are described below.

6.2 Measurement System Components.

6.2.1 Sample Probe. A single extraction-point probe constructed of glass, stainless steel or other non-reactive material, and of length sufficient to reach any designated sampling point. The sample probe must be designed to prevent plugging due to condensation or particulate matter.

6.2.2 Sample Line. Non-reactive tubing to transport the effluent from the sample probe to the EC cell.

6.2.3 Calibration Assembly (optional). A three-way valve assembly or equivalent to introduce calibration gases at ambient pressure at the exit end of the sample probe during calibration checks. The assembly must be designed such that only stack gas or calibration gas flows in the sample line and all gases flow through any gas path filters.

6.2.4 Particulate Filter (optional). Filters before the inlet of the EC cell to prevent accumulation of particulate material in the measurement system and extend the useful life of the components. All filters must be fabricated of materials that are non-reactive to the gas mixtures being sampled.

6.2.5 Sample Pump. A leak-free pump to provide undiluted sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If located upstream of the EC cells, the pump must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.8 Sample Flow Rate Monitoring. An adjustable rotameter or equivalent device used to adjust and maintain the sample flow rate through the analyzer as prescribed.

6.2.9 Sample Gas Manifold (optional). A manifold to divert a portion of the sample gas stream to the analyzer and the remainder to a by-pass discharge vent. The sample gas manifold may also include provisions for introducing calibration gases directly to the analyzer. The manifold must be constructed of a material that is non-reactive to the gas mixtures being sampled.

6.2.10 EC cell. A device containing one or more EC cells to determine the CO and O₂ concentrations in the sample gas stream. The EC cell(s) must meet the applicable performance specifications of Section 13 of this protocol.

6.2.11 Data Recorder. A strip chart recorder, computer or digital recorder to make a record of analyzer output data. The data recorder resolution (i.e., readability) must be no greater than 1 ppm for CO; 0.1 percent for O₂; and one degree (either °C or °F) for temperature. Alternatively, you may use a digital or analog meter having the same resolution to observe and manually record the analyzer responses.

6.2.12 Interference Gas Filter or Scrubber. A device to remove interfering compounds upstream of the CO EC cell. Specific interference gas filters or scrubbers used in the performance-established configuration of the analyzer must continue to be used. Such a filter or scrubber must have a means to determine when the removal agent is exhausted. Periodically replace or replenish it in accordance with the manufacturer's recommendations.

7.0 REAGENTS AND STANDARDS. WHAT CALIBRATION GASES ARE NEEDED?

7.1 Calibration Gases. CO calibration gases for the EC cell must be CO in nitrogen or CO in a mixture of nitrogen and O₂. Use CO calibration gases with labeled concentration values certified by the manufacturer to be within ±5 percent of the label value. Dry ambient air (20.9 percent O₂) is acceptable for calibration of the O₂ cell. If needed, any lower percentage O₂ calibration gas must be a mixture of O₂ in nitrogen.

7.1.1 Up-Scale CO Calibration Gas Concentration. Choose one or more up-scale gas concentrations such that the average of the stack gas measurements for each stack gas sampling run are between 25 and 150 percent of those concentrations. Alternatively, choose an up-scale gas that does not exceed twice the concentration of the applicable outlet standard. If a measured gas value exceeds 150 percent of the up-scale CO calibration gas value at any time during the stack gas sampling run, the run must be discarded and repeated.

7.1.2 Up-Scale O₂ Calibration Gas Concentration.

Select an O₂ gas concentration such that the difference between the gas concentration and the average stack gas measurement or reading for each sample run is less than 15 percent O₂. When the average exhaust gas O₂ readings are above 6 percent, you may use dry ambient air (20.9 percent O₂) for the up-scale O₂ calibration gas.

7.1.3 Zero Gas. Use an inert gas that contains less than 0.25 percent of the up-scale CO calibration gas concentration. You may use dry air that is free from ambient CO and other combustion gas products (e.g., CO₂).

8.0 SAMPLE COLLECTION AND ANALYSIS

8.1 Selection of Sampling Sites.

8.1.1 Control Device Inlet. Select a sampling site sufficiently downstream of the engine so that the combustion gases should be well mixed. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.1.2 Exhaust Gas Outlet. Select a sampling site located at least two stack diameters downstream of any disturbance (e.g., turbocharger exhaust, crossover junction or recirculation take-off) and at least one-half stack diameter upstream of the gas discharge to the atmosphere. Use a single sampling extraction point near the center of the duct (e.g., within the 10 percent centroidal area), unless instructed otherwise.

8.2 Stack Gas Collection and Analysis. Prior to the first stack gas sampling run, conduct that the pre-sampling calibration in accordance with Section 10.1. Use Figure 1 to record all data. Zero the analyzer with zero gas. Confirm and record that the scrubber media color is correct and not exhausted. Then position the probe at the sampling point and begin the sampling run at the same flow rate used during the up-scale calibration. Record the start time. Record all EC cell output responses and the flow rate during the “sample conditioning phase” once per minute until constant readings are obtained. Then begin the “measurement data phase” and record readings every 15 seconds for at least two minutes (or eight readings), or as otherwise required to achieve two continuous minutes of data that meet the specification given in Section 13.1. Finally, perform the “refresh phase” by introducing dry air, free from CO and other combustion gases, until several minute-to-minute readings of consistent value have been obtained. For each run use the “measurement data phase” readings to calculate the average stack gas CO and O₂ concentrations.

8.3 EC Cell Rate. Maintain the EC cell sample flow rate so that it does not vary by more than ±10 percent throughout the pre-sampling calibration, stack gas sampling and post-sampling calibration check. Alternatively, the EC cell sample flow rate can be maintained within a tolerance range that does not affect the gas concentration readings by more than ±3 percent, as instructed by the EC cell manufacturer.

9.0 QUALITY CONTROL (RESERVED)

10.0 CALIBRATION AND STANDARDIZATION

10.1 Pre-Sampling Calibration. Conduct the following protocol once for each nominal range to be used on each EC cell before performing a stack gas sampling run on each field sampling day. Repeat the calibration if you replace an EC cell before completing all of the sampling runs. There is no prescribed order for calibration of the EC cells; however, each cell must complete the measurement data phase during calibration. Assemble the measurement system by following the manufacturer's recommended protocols including for preparing and preconditioning the EC cell.

Assure the measurement system has no leaks and verify the gas scrubbing agent is not depleted. Use Figure 1 to record all data.

10.1.1 Zero Calibration. For both the O₂ and CO cells, introduce zero gas to the measurement system (e.g., at the calibration assembly) and record the concentration reading every minute until readings are constant for at least two consecutive minutes. Include the time and sample flow rate. Repeat the steps in this section at least once to verify the zero calibration for each component gas.

10.1.2 Zero Calibration Tolerance. For each zero gas introduction, the zero level output must be less than or equal to ± 3 percent of the up-scale gas value or ± 1 ppm, whichever is less restrictive, for the CO channel and less than or equal to ± 0.3 percent O₂ for the O₂ channel.

10.1.3 Up-Scale Calibration. Individually introduce each calibration gas to the measurement system (e.g., at the calibration assembly) and record the start time. Record all EC cell output responses and the flow rate during this "sample conditioning phase" once per minute until readings are constant for at least two minutes. Then begin the "measurement data phase" and record readings every 15 seconds for a total of two minutes, or as otherwise required. Finally, perform the "refresh phase" by introducing dry air, free from CO and other combustion gases, until readings are constant for at least two consecutive minutes. Then repeat the steps in this section at least once to verify the calibration for each component gas. Introduce all gases to flow through the entire sample handling system (i.e., at the exit end of the sampling probe or the calibration assembly).

10.1.4 Up-Scale Calibration Error. The mean of the difference of the "measurement data phase" readings from the reported standard gas value must be less than or equal to ± 5 percent or ± 1 ppm for CO or ± 0.5 percent O₂, whichever is less restrictive, respectively. The maximum allowable deviation from the mean measured value of any single "measurement data phase" reading must be less than or equal to ± 2 percent or ± 1 ppm for CO or ± 0.5 percent O₂, whichever is less restrictive, respectively.

10.2 Post-Sampling Calibration Check. Conduct a stack gas post-sampling calibration check after the stack gas sampling run or set of runs and within 12 hours of the initial calibration. Conduct up-scale and zero calibration checks using the protocol in Section 10.1. Make no changes to the sampling system or EC cell calibration until all post-sampling calibration checks have been recorded. If either the zero or up-scale calibration error exceeds the respective specification in Sections 10.1.2 and 10.1.4 then all measurement data collected since the previous successful calibrations are invalid and re-calibration and re-sampling are required. If the sampling system is disassembled or the EC cell calibration is adjusted, repeat the calibration check before conducting the next analyzer sampling run.

11.0 ANALYTICAL PROCEDURE

The analytical procedure is fully discussed in Section 8.

12.0 CALCULATIONS AND DATA ANALYSIS

Determine the CO and O₂ concentrations for each stack gas sampling run by calculating the mean gas concentrations of the data recorded during the "measurement data phase".

13.0 PROTOCOL PERFORMANCE

Use the following protocols to verify consistent analyzer performance during each field sampling day.

13.1 Measurement Data Phase Performance Check. Calculate the mean of the readings from the “measurement data phase”. The maximum allowable deviation from the mean for each of the individual readings is ± 2 percent, or ± 1 ppm, whichever is less restrictive. Record the mean value and maximum deviation for each gas monitored. Data must conform to Section 10.1.4. The EC cell flow rate must conform to the specification in Section 8.3.

Example: A measurement data phase is invalid if the maximum deviation of any single reading comprising that mean is greater than ± 2 percent or ± 1 ppm (the default criteria). For example, if the mean = 30 ppm, single readings of below 29 ppm and above 31 ppm are disallowed).

13.2 Interference Check. Before the initial use of the EC cell and interference gas scrubber in the field, and semi-annually thereafter, challenge the interference gas scrubber with NO and NO₂ gas standards that are generally recognized as representative of diesel-fueled engine NO and NO₂ emission values. Record the responses displayed by the CO EC cell and other pertinent data on Figure 1 or a similar form.

13.2.1 Interference Response. The combined NO and NO₂ interference response should be less than or equal to ± 5 percent of the up-scale CO calibration gas concentration.

13.3 Repeatability Check. Conduct the following check once for each nominal range that is to be used on the CO EC cell within 5 days prior to each field sampling program. If a field sampling program lasts longer than 5 days, repeat this check every 5 days. Immediately repeat the check if the EC cell is replaced or if the EC cell is exposed to gas concentrations greater than 150 percent of the highest up-scale gas concentration.

13.3.1 Repeatability Check Procedure. Perform a complete EC cell sampling run (all three phases) by introducing the CO calibration gas to the measurement system and record the response. Follow Section 10.1.3. Use Figure 1 to record all data. Repeat the run three times for a total of four complete runs. During the four repeatability check runs, do not adjust the system except where necessary to achieve the correct calibration gas flow rate at the analyzer.

13.3.2 Repeatability Check Calculations. Determine the highest and lowest average “measurement data phase” CO concentrations from the four repeatability check runs and record the results on Figure 1 or a similar form. The absolute value of the difference between the maximum and minimum average values recorded must not vary more than ± 3 percent or ± 1 ppm of the up-scale gas value, whichever is less restrictive.

14.0 POLLUTION PREVENTION (RESERVED)

15.0 WASTE MANAGEMENT (RESERVED)

16.0 ALTERNATIVE PROCEDURES (RESERVED)

17.0 REFERENCES

(1) “Development of an Electrochemical Cell Emission Analyzer Test Protocol”, Topical Report, Phil Juneau, Emission Monitoring, Inc., July 1997.

(2) "Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers, and Process Heaters Using Portable Analyzers", EMC Conditional Test Protocol 30 (CTM-30), Gas Research Institute Protocol GRI-96/0008, Revision 7, October 13, 1997.

(3) "ICAC Test Protocol for Periodic Monitoring", EMC Conditional Test Protocol 34 (CTM-034), The Institute of Clean Air Companies, September 8, 1999.

(4) "Code of Federal Regulations", Protection of Environment, 40 CFR, Part 60, Appendix A, Methods 1-4; 10.

TABLE 1: APPENDIX A—SAMPLING RUN DATA.

Facility _____				Engine I.D. _____				Date _____				
Run Type:	()				()				()		()	
(X)	Pre-Sample Calibration				Stack Gas Sample				Post-Sample Cal. Check		Repeatability Check	
Run #	1	1	2	2	3	3	4	4	Time	Scrub. OK	Flow- Rate	
Gas	O ₂	CO	O ₂	CO	O ₂	CO	O ₂	CO				
Sample Cond. Phase												
"												
"												
"												
"												
Measurement Data Phase												
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Mean											
Refresh Phase											
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[78 FR 6721, Jan. 30, 2013]

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Subpart JJJ—Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

SOURCE: 73 FR 3591, Jan. 18, 2008, unless otherwise noted.

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WHAT THIS SUBPART COVERS

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§60.4230 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary spark ignition (SI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (6) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary SI ICE with a maximum engine power less than or equal to 19 kilowatt (KW) (25 horsepower (HP)) that are manufactured on or after July 1, 2008.

(2) Manufacturers of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are gasoline fueled or that are rich burn engines fueled by liquefied petroleum gas (LPG), where the date of manufacture is:

(i) On or after July 1, 2008; or

(ii) On or after January 1, 2009, for emergency engines.

(3) Manufacturers of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are not gasoline fueled and are not rich burn engines fueled by LPG, where the manufacturer participates in the voluntary manufacturer certification program described in this subpart and where the date of manufacture is:

(i) On or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);

(ii) On or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP;

(iii) On or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or

(iv) On or after January 1, 2009, for emergency engines.

(4) Owners and operators of stationary SI ICE that commence construction after June 12, 2006, where the stationary SI ICE are manufactured:

(i) On or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);

(ii) on or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP;

(iii) on or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or

(iv) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP).

(5) Owners and operators of stationary SI ICE that are modified or reconstructed after June 12, 2006, and any person that modifies or reconstructs any stationary SI ICE after June 12, 2006.

(6) The provisions of §60.4236 of this subpart are applicable to all owners and operators of stationary SI ICE that commence construction after June 12, 2006.

(b) The provisions of this subpart are not applicable to stationary SI ICE being tested at an engine test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(d) For the purposes of this subpart, stationary SI ICE using alcohol-based fuels are considered gasoline engines.

(e) Stationary SI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR parts 90 and 1048, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(f) Owners and operators of facilities with internal combustion engines that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

[73 FR 3591, Jan. 18, 2008, as amended at 76 FR 37972, June 28, 2011]

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EMISSION STANDARDS FOR MANUFACTURERS

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§60.4231 What emission standards must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing such engines?

(a) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) manufactured on or after July 1, 2008 to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 1054, as follows:

If engine displacement is * * *	and manufacturing dates are * * *	the engine must meet emission standards and related requirements for nonhandheld engines under * * *
(1) below 225 cc	July 1, 2008 to December 31, 2011	40 CFR part 90.
(2) below 225 cc	January 1, 2012 or later	40 CFR part 1054.
(3) at or above 225 cc	July 1, 2008 to December 31, 2010	40 CFR part 90.
(4) at or above 225 cc	January 1, 2011 or later	40 CFR part 1054.

(b) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) that use gasoline and that are manufactured on or after the applicable date in §60.4230(a)(2), or manufactured on or after the applicable date in §60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers must certify their emergency stationary SI ICE with a maximum engine power greater than 25 HP and less than 130 HP that use gasoline and that are manufactured on or after the applicable date in §60.4230(a)(4) to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, and other requirements for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cubic centimeters (cc) that use gasoline to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 1054, as appropriate.

(c) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a

maximum engine power greater than 25 HP and less than 130 HP) that are rich burn engines that use LPG and that are manufactured on or after the applicable date in §60.4230(a)(2), or manufactured on or after the applicable date in §60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers must certify their emergency stationary SI ICE greater than 25 HP and less than 130 HP that are rich burn engines that use LPG and that are manufactured on or after the applicable date in §60.4230(a)(4) to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, and other requirements for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc that are rich burn engines that use LPG to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 1054, as appropriate.

(d) Stationary SI internal combustion engine manufacturers who choose to certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG and emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) under the voluntary manufacturer certification program described in this subpart must certify those engines to the certification emission standards for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers who choose to certify their emergency stationary SI ICE greater than 25 HP and less than 130 HP (except gasoline and rich burn engines that use LPG), must certify those engines to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc (except gasoline and rich burn engines that use LPG) to the certification emission standards for new nonroad SI engines in 40 CFR part 90 or 1054, as appropriate. For stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG and emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) manufactured prior to January 1, 2011, manufacturers may choose to certify these engines to the standards in Table 1 to this subpart applicable to engines with a maximum engine power greater than or equal to 100 HP and less than 500 HP.

(e) Stationary SI internal combustion engine manufacturers who choose to certify their stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) under the voluntary manufacturer certification program described in this subpart must certify those engines to the emission standards in Table 1 to this subpart. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) that are lean burn engines that use LPG to the certification emission standards for new nonroad SI engines in 40 CFR part 1048. For stationary SI ICE with a maximum engine power greater than or equal to 100 HP (75 KW) and less than 500 HP (373 KW) manufactured prior to January 1, 2011, and for stationary SI ICE with a maximum engine power greater than or equal to 500 HP (373 KW) manufactured prior to July 1, 2010, manufacturers may choose to certify these engines to the certification emission standards for new nonroad SI engines in 40 CFR part 1048 applicable to engines that are not severe duty engines.

(f) Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, to the extent they apply to equipment manufacturers.

(g) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary SI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed stationary SI ICE.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59175, Oct. 8, 2008; 76 FR 37973, June 28, 2011; 78 FR 6697, Jan. 30, 2013]

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§60.4232 How long must my engines meet the emission standards if I am a manufacturer of stationary SI internal combustion engines?

Engines manufactured by stationary SI internal combustion engine manufacturers must meet the emission standards as required in §60.4231 during the certified emissions life of the engines.

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EMISSION STANDARDS FOR OWNERS AND OPERATORS

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§60.4233 What emission standards must I meet if I am an owner or operator of a stationary SI internal combustion engine?

(a) Owners and operators of stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) manufactured on or after July 1, 2008, must comply with the emission standards in §60.4231(a) for their stationary SI ICE.

(b) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) manufactured on or after the applicable date in §60.4230(a)(4) that use gasoline must comply with the emission standards in §60.4231(b) for their stationary SI ICE.

(c) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) manufactured on or after the applicable date in §60.4230(a)(4) that are rich burn engines that use LPG must comply with the emission standards in §60.4231(c) for their stationary SI ICE.

(d) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) must comply with the emission standards for field testing in 40 CFR 1048.101(c) for their non-emergency stationary SI ICE and with the emission standards in Table 1 to this subpart for their emergency

stationary SI ICE. Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) manufactured prior to January 1, 2011, that were certified to the standards in Table 1 to this subpart applicable to engines with a maximum engine power greater than or equal to 100 HP and less than 500 HP, may optionally choose to meet those standards.

(e) Owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) must comply with the emission standards in Table 1 to this subpart for their stationary SI ICE. For owners and operators of stationary SI ICE with a maximum engine power greater than or equal to 100 HP (except gasoline and rich burn engines that use LPG) manufactured prior to January 1, 2011 that were certified to the certification emission standards in 40 CFR part 1048 applicable to engines that are not severe duty engines, if such stationary SI ICE was certified to a carbon monoxide (CO) standard above the standard in Table 1 to this subpart, then the owners and operators may meet the CO certification (not field testing) standard for which the engine was certified.

(f) Owners and operators of any modified or reconstructed stationary SI ICE subject to this subpart must meet the requirements as specified in paragraphs (f)(1) through (5) of this section.

(1) Owners and operators of stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with emission standards in §60.4231(a) for their stationary SI ICE. Engines with a date of manufacture prior to July 1, 2008 must comply with the emission standards specified in §60.4231(a) applicable to engines manufactured on July 1, 2008.

(2) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are gasoline engines and are modified or reconstructed after June 12, 2006, must comply with the emission standards in §60.4231(b) for their stationary SI ICE. Engines with a date of manufacture prior to July 1, 2008 (or January 1, 2009 for emergency engines) must comply with the emission standards specified in §60.4231(b) applicable to engines manufactured on July 1, 2008 (or January 1, 2009 for emergency engines).

(3) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are rich burn engines that use LPG, that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in §60.4231(c). Engines with a date of manufacture prior to July 1, 2008 (or January 1, 2009 for emergency engines) must comply with the emission standards specified in §60.4231(c) applicable to engines manufactured on July 1, 2008 (or January 1, 2009 for emergency engines).

(4) Owners and operators of stationary SI natural gas and lean burn LPG engines with a maximum engine power greater than 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (d) or (e) of this section, except that such owners and operators of non-emergency engines and emergency engines greater than or equal to 130 HP must meet a nitrogen oxides (NO_x) emission standard of 3.0 grams per HP-hour (g/HP-hr), a CO emission standard of 4.0 g/HP-hr (5.0 g/HP-hr for non-emergency engines less than 100 HP), and a volatile organic compounds (VOC) emission standard of

1.0 g/HP-hr, or a NO_x emission standard of 250 ppmvd at 15 percent oxygen (O₂), a CO emission standard 540 ppmvd at 15 percent O₂ (675 ppmvd at 15 percent O₂ for non-emergency engines less than 100 HP), and a VOC emission standard of 86 ppmvd at 15 percent O₂, where the date of manufacture of the engine is:

(i) Prior to July 1, 2007, for non-emergency engines with a maximum engine power greater than or equal to 500 HP (except lean burn natural gas engines and LPG engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);

(ii) Prior to July 1, 2008, for non-emergency engines with a maximum engine power less than 500 HP;

(iii) Prior to January 1, 2009, for emergency engines;

(iv) Prior to January 1, 2008, for non-emergency lean burn natural gas engines and LPG engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP.

(5) Owners and operators of stationary SI landfill/digester gas ICE engines with a maximum engine power greater than 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (e) of this section for stationary landfill/digester gas engines. Engines with maximum engine power less than 500 HP and a date of manufacture prior to July 1, 2008 must comply with the emission standards specified in paragraph (e) of this section for stationary landfill/digester gas ICE with a maximum engine power less than 500 HP manufactured on July 1, 2008. Engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines greater than or equal to 500 HP and less than 1,350 HP) and a date of manufacture prior to July 1, 2007 must comply with the emission standards specified in paragraph (e) of this section for stationary landfill/digester gas ICE with a maximum engine power greater than or equal to 500 HP (except lean burn engines greater than or equal to 500 HP and less than 1,350 HP) manufactured on July 1, 2007. Lean burn engines greater than or equal to 500 HP and less than 1,350 HP with a date of manufacture prior to January 1, 2008 must comply with the emission standards specified in paragraph (e) of this section for stationary landfill/digester gas ICE that are lean burn engines greater than or equal to 500 HP and less than 1,350 HP and manufactured on January 1, 2008.

(g) Owners and operators of stationary SI wellhead gas ICE engines may petition the Administrator for approval on a case-by-case basis to meet emission standards no less stringent than the emission standards that apply to stationary emergency SI engines greater than 25 HP and less than 130 HP due to the presence of high sulfur levels in the fuel, as specified in Table 1 to this subpart. The request must, at a minimum, demonstrate that the fuel has high sulfur levels that prevent the use of aftertreatment controls and also that the owner has reasonably made all attempts possible to obtain an engine that will meet the standards without the use of aftertreatment controls. The petition must request the most stringent standards reasonably applicable to the engine using the fuel.

(h) Owners and operators of stationary SI ICE that are required to meet standards that reference 40 CFR 1048.101 must, if testing their engines in use, meet the standards in that section applicable to field testing, except as indicated in paragraph (e) of this section.

[73 FR 3591, Jan. 18, 2008, as amended at 76 FR 37973, June 28, 2011]

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§60.4234 How long must I meet the emission standards if I am an owner or operator of a stationary SI internal combustion engine?

Owners and operators of stationary SI ICE must operate and maintain stationary SI ICE that achieve the emission standards as required in §60.4233 over the entire life of the engine.

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OTHER REQUIREMENTS FOR OWNERS AND OPERATORS

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§60.4235 What fuel requirements must I meet if I am an owner or operator of a stationary SI gasoline fired internal combustion engine subject to this subpart?

Owners and operators of stationary SI ICE subject to this subpart that use gasoline must use gasoline that meets the per gallon sulfur limit in 40 CFR 1090.205.

[73 FR 3591, Jan. 18, 2008, as amended at 85 FR 78463, Dec. 4, 2020]

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§60.4236 What is the deadline for importing or installing stationary SI ICE produced in previous model years?

(a) After July 1, 2010, owners and operators may not install stationary SI ICE with a maximum engine power of less than 500 HP that do not meet the applicable requirements in §60.4233.

(b) After July 1, 2009, owners and operators may not install stationary SI ICE with a maximum engine power of greater than or equal to 500 HP that do not meet the applicable requirements in §60.4233, except that lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP that do not meet the applicable requirements in §60.4233 may not be installed after January 1, 2010.

(c) For emergency stationary SI ICE with a maximum engine power of greater than 19 KW (25 HP), owners and operators may not install engines that do not meet the applicable requirements in §60.4233 after January 1, 2011.

(d) In addition to the requirements specified in §§60.4231 and 60.4233, it is prohibited to import stationary SI ICE less than or equal to 19 KW (25 HP), stationary rich burn LPG SI ICE, and stationary gasoline SI ICE that do not meet the applicable requirements specified in paragraphs (a), (b), and (c) of this section, after the date specified in paragraph (a), (b), and (c) of this section.

(e) The requirements of this section do not apply to owners and operators of stationary SI ICE that have been modified or reconstructed, and they do not apply to engines that were removed from one existing location and reinstalled at a new location.

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§60.4237 What are the monitoring requirements if I am an owner or operator of an emergency stationary SI internal combustion engine?

(a) Starting on July 1, 2010, if the emergency stationary SI internal combustion engine that is greater than or equal to 500 HP that was built on or after July 1, 2010, does not meet the standards applicable to non-emergency engines, the owner or operator must install a non-resettable hour meter.

(b) Starting on January 1, 2011, if the emergency stationary SI internal combustion engine that is greater than or equal to 130 HP and less than 500 HP that was built on or after January 1, 2011, does not meet the standards applicable to non-emergency engines, the owner or operator must install a non-resettable hour meter.

(c) If you are an owner or operator of an emergency stationary SI internal combustion engine that is less than 130 HP, was built on or after July 1, 2008, and does not meet the standards applicable to non-emergency engines, you must install a non-resettable hour meter upon startup of your emergency engine.

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COMPLIANCE REQUIREMENTS FOR MANUFACTURERS

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§60.4238 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines $\leq$ 19 KW (25 HP) or a manufacturer of equipment containing such engines?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in §60.4231(a) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 90, subpart B, or 40 CFR part 1054, subpart C, as applicable, and must test their engines as specified in those parts. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

[73 FR 59176, Oct. 8, 2008]

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§60.4239 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that use gasoline or a manufacturer of equipment containing such engines?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in §60.4231(b) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must test their engines as specified in that part. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 40 CFR part 1054, and manufacturers of stationary SI emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, must certify their stationary SI ICE using the certification procedures required in 40 CFR part 90, subpart B, or 40 CFR part 1054, subpart C, as applicable, and must test their engines as specified in those parts. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

[73 FR 59176, Oct. 8, 2008]

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§60.4240 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that are rich burn engines that use LPG or a manufacturer of equipment containing such engines?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in §60.4231(c) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must test their engines as specified in that part. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 40 CFR part 1054, and manufacturers of stationary SI emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, must certify their stationary SI ICE using the certification procedures required in 40 CFR part 90, subpart B, or 40 CFR part 1054, subpart C, as applicable, and must test their engines as specified in those parts. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

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§60.4241 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines participating in the voluntary certification program or a manufacturer of equipment containing such engines?

(a) Manufacturers of stationary SI internal combustion engines with a maximum engine power greater than 19 KW (25 HP) that do not use gasoline and are not rich burn engines that use LPG can choose to certify their engines to the emission standards in §60.4231(d) or (e), as applicable, under the voluntary certification program described in this subpart. Manufacturers who certify their engines under the voluntary certification program must meet the requirements as specified in paragraphs (b) through (g) of this section. In addition, manufacturers of stationary SI internal combustion engines who choose to certify their engines under the voluntary certification program, must also meet the requirements as specified in §60.4247.

(b) Manufacturers of engines other than those certified to standards in 40 CFR part 90 or 40 CFR part 1054 must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must follow the same test procedures that apply to large SI nonroad engines under 40 CFR part 1048, but must use the D-1 cycle of International Organization of Standardization 8178-4: 1996(E) (incorporated by reference, see 40 CFR 60.17) or the test cycle requirements specified in Table 3 to 40 CFR 1048.505, except that Table 3 of 40 CFR 1048.505 applies to high load engines only. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 40 CFR part 1054, and manufacturers of emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 standards in 40 CFR 90.103, applicable to class II engines, must certify their stationary SI ICE using the certification procedures required in 40 CFR part 90, subpart B, or 40 CFR part 1054, subpart C, as applicable, and must test their engines as specified in those parts. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

(c) Certification of stationary SI ICE to the emission standards specified in §60.4231(d) or (e), as applicable, is voluntary, but manufacturers who decide to certify are subject to all of the requirements indicated in this subpart with regard to the engines included in their certification. Manufacturers must clearly label their stationary SI engines as certified or non-certified engines.

(d) Manufacturers of natural gas fired stationary SI ICE who conduct voluntary certification of stationary SI ICE to the emission standards specified in §60.4231(d) or (e), as applicable, must certify their engines for operation using fuel that meets the definition of pipeline-quality natural gas. The fuel used for certifying stationary SI natural gas engines must meet the definition of pipeline-quality natural gas as described in §60.4248. In addition, the manufacturer must provide information to the owner and operator of the certified stationary SI engine including the specifications of the pipeline-

quality natural gas to which the engine is certified and what adjustments the owner or operator must make to the engine when installed in the field to ensure compliance with the emission standards.

(e) Manufacturers of stationary SI ICE that are lean burn engines fueled by LPG who conduct voluntary certification of stationary SI ICE to the emission standards specified in §60.4231(d) or (e), as applicable, must certify their engines for operation using fuel that meets the specifications in 40 CFR 1065.720.

(f) Manufacturers may certify their engines for operation using gaseous fuels in addition to pipeline-quality natural gas; however, the manufacturer must specify the properties of that fuel and provide testing information showing that the engine will meet the emission standards specified in §60.4231(d) or (e), as applicable, when operating on that fuel. The manufacturer must also provide instructions for configuring the stationary engine to meet the emission standards on fuels that do not meet the pipeline-quality natural gas definition. The manufacturer must also provide information to the owner and operator of the certified stationary SI engine regarding the configuration that is most conducive to reduced emissions where the engine will be operated on gaseous fuels with different quality than the fuel that it was certified to.

(g) A stationary SI engine manufacturer may certify an engine family solely to the standards applicable to landfill/digester gas engines as specified in §60.4231(d) or (e), as applicable, but must certify their engines for operation using landfill/digester gas and must add a permanent label stating that the engine is for use only in landfill/digester gas applications. The label must be added according to the labeling requirements specified in 40 CFR 1048.135(b).

(h) For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

(i) For engines being certified to the voluntary certification standards in Table 1 of this subpart, the VOC measurement shall be made by following the procedures in 40 CFR 1065.260 and 1065.265 in order to determine the total NMHC emissions by using a flame-ionization detector and non-methane cutter. As an alternative to the nonmethane cutter, manufacturers may use a gas chromatograph as allowed under 40 CFR 1065.267 and may measure ethane, as well as methane, for excluding such levels from the total VOC measurement.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59176, Oct. 8, 2008; 76 FR 37974, June 28, 2011]

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§60.4242 What other requirements must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing stationary SI internal combustion engines or a manufacturer of equipment containing such engines?

(a) Stationary SI internal combustion engine manufacturers must meet the provisions of 40 CFR part 90, 40 CFR part 1048, or 40 CFR part 1054, as applicable, as well as 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1048 or 1054, except that engines certified pursuant to the voluntary certification procedures in §60.4241 are subject only to the provisions

indicated in §60.4247 and are permitted to provide instructions to owners and operators allowing for deviations from certified configurations, if such deviations are consistent with the provisions of paragraphs §60.4241(c) through (f). Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, as applicable. Labels on engines certified to 40 CFR part 1048 must refer to stationary engines, rather than or in addition to nonroad engines, as appropriate.

(b) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR part 90, 40 CFR part 1048, or 40 CFR part 1054 for that model year may certify any such family that contains both nonroad and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts. This provision also applies to equipment or component manufacturers certifying to standards under 40 CFR part 1060.

(c) Manufacturers of engine families certified to 40 CFR part 1048 may meet the labeling requirements referred to in paragraph (a) of this section for stationary SI ICE by either adding a separate label containing the information required in paragraph (a) of this section or by adding the words "and stationary" after the word "nonroad" to the label.

(d) For all engines manufactured on or after January 1, 2011, and for all engines with a maximum engine power greater than 25 HP and less than 130 HP manufactured on or after July 1, 2008, a stationary SI engine manufacturer that certifies an engine family solely to the standards applicable to emergency engines must add a permanent label stating that the engines in that family are for emergency use only. The label must be added according to the labeling requirements specified in 40 CFR 1048.135(b).

(e) All stationary SI engines subject to mandatory certification that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230. Stationary SI engines subject to standards in 40 CFR part 90 may use the provisions in 40 CFR 90.909. Manufacturers of stationary engines with a maximum engine power greater than 25 HP that are not certified to standards and other requirements under 40 CFR part 1048 are subject to the labeling provisions of 40 CFR 1048.20 pertaining to excluded stationary engines.

(f) For manufacturers of gaseous-fueled stationary engines required to meet the warranty provisions in 40 CFR 90.1103 or 1054.120, we may establish an hour-based warranty period equal to at least the certified emissions life of the engines (in engine operating hours) if we determine that these engines are likely to operate for a number of hours greater than the applicable useful life within 24 months. We will not approve an alternate warranty under this paragraph (f) for nonroad engines. An alternate warranty period approved under this paragraph (f) will be the specified number of engine operating hours or two years, whichever comes first. The engine manufacturer shall request this alternate warranty period in its application for certification or in an earlier submission. We may approve an alternate warranty period for an engine family subject to the following conditions:

(1) The engines must be equipped with non-resettable hour meters.

(2) The engines must be designed to operate for a number of hours substantially greater than the applicable certified emissions life.

(3) The emission-related warranty for the engines may not be shorter than any published warranty offered by the manufacturer without charge for the engines. Similarly, the emission-related warranty for any component shall not be shorter than any published warranty offered by the manufacturer without charge for that component.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59177, Oct. 8, 2008]

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COMPLIANCE REQUIREMENTS FOR OWNERS AND OPERATORS

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§60.4243 What are my compliance requirements if I am an owner or operator of a stationary SI internal combustion engine?

(a) If you are an owner or operator of a stationary SI internal combustion engine that is manufactured after July 1, 2008, and must comply with the emission standards specified in §60.4233(a) through (c), you must comply by purchasing an engine certified to the emission standards in §60.4231(a) through (c), as applicable, for the same engine class and maximum engine power. In addition, you must meet one of the requirements specified in (a)(1) and (2) of this section.

(1) If you operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, you must keep records of conducted maintenance to demonstrate compliance, but no performance testing is required if you are an owner or operator. You must also meet the requirements as specified in 40 CFR part 1068, subparts A through D, as they apply to you. If you adjust engine settings according to and consistent with the manufacturer's instructions, your stationary SI internal combustion engine will not be considered out of compliance.

(2) If you do not operate and maintain the certified stationary SI internal combustion engine and control device according to the manufacturer's emission-related written instructions, your engine will be considered a non-certified engine, and you must demonstrate compliance according to (a)(2)(i) through (iii) of this section, as appropriate.

(i) If you are an owner or operator of a stationary SI internal combustion engine less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions, but no performance testing is required if you are an owner or operator.

(ii) If you are an owner or operator of a stationary SI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test within 1 year of engine startup to demonstrate compliance.

(iii) If you are an owner or operator of a stationary SI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test within 1 year of engine startup and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

(b) If you are an owner or operator of a stationary SI internal combustion engine and must comply with the emission standards specified in §60.4233(d) or (e), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) and (2) of this section.

(1) Purchasing an engine certified according to procedures specified in this subpart, for the same model year and demonstrating compliance according to one of the methods specified in paragraph (a) of this section.

(2) Purchasing a non-certified engine and demonstrating compliance with the emission standards specified in §60.4233(d) or (e) and according to the requirements specified in §60.4244, as applicable, and according to paragraphs (b)(2)(i) and (ii) of this section.

(i) If you are an owner or operator of a stationary SI internal combustion engine greater than 25 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance.

(ii) If you are an owner or operator of a stationary SI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

(c) If you are an owner or operator of a stationary SI internal combustion engine that must comply with the emission standards specified in §60.4233(f), you must demonstrate compliance according paragraph (b)(2)(i) or (ii) of this section, except that if you comply according to paragraph (b)(2)(i) of this section, you demonstrate that your non-certified engine complies with the emission standards specified in §60.4233(f).

(d) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (d)(1) through (3) of this section. In order

for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (d)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (d)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (d)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (d)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (d)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (d)(2) of this section. Except as provided in paragraph (d)(3)(i) of this section, the 50 hours per year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(e) Owners and operators of stationary SI natural gas fired engines may operate their engines using propane for a maximum of 100 hours per year as an alternative fuel solely during emergency operations, but must keep records of such use. If propane is used for more than 100 hours per year in an engine that is not certified to the emission standards when using propane, the owners and operators are required to conduct a performance test to demonstrate compliance with the emission standards of §60.4233.

(f) If you are an owner or operator of a stationary SI internal combustion engine that is less than or equal to 500 HP and you purchase a non-certified engine or you do not operate and maintain your certified stationary SI internal combustion engine and control device according to the manufacturer's written emission-related instructions, you are required to perform initial performance testing as indicated in this section, but you are not required to conduct subsequent performance testing unless the stationary engine is rebuilt or undergoes major repair or maintenance. A rebuilt stationary SI ICE means an engine that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(g) It is expected that air-to-fuel ratio controllers will be used with the operation of three-way catalysts/non-selective catalytic reduction. The AFR controller must be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times.

(h) If you are an owner/operator of an stationary SI internal combustion engine with maximum engine power greater than or equal to 500 HP that is manufactured after July 1, 2007 and before July 1, 2008, and must comply with the emission standards specified in sections 60.4233(b) or (c), you must comply by one of the methods specified in paragraphs (h)(1) through (h)(4) of this section.

(1) Purchasing an engine certified according to 40 CFR part 1048. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(i) If you are an owner or operator of a modified or reconstructed stationary SI internal combustion engine and must comply with the emission standards specified in §60.4233(f), you must demonstrate compliance according to one of the methods specified in paragraphs (i)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in §60.4233(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in §60.4244. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

[73 FR 3591, Jan. 18, 2008, as amended at 76 FR 37974, June 28, 2011; 78 FR 6697, Jan. 30, 2013]

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TESTING REQUIREMENTS FOR OWNERS AND OPERATORS

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§60.4244 What test methods and other procedures must I use if I am an owner or operator of a stationary SI internal combustion engine?

Owners and operators of stationary SI ICE who conduct performance tests must follow the procedures in paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and according to the requirements in §60.8 and under the specific conditions that are specified by Table 2 to this subpart.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c). If your stationary SI internal combustion engine is non-operational, you do not need to startup the engine solely to conduct a performance test; however, you must conduct the performance test immediately upon startup of the engine.

(c) You must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must be conducted within 10 percent of 100 percent peak (or the highest achievable) load and last at least 1 hour.

(d) To determine compliance with the NO_x mass per unit output emission limitation, convert the concentration of NO_x in the engine exhaust using Equation 1 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{HP-hr} \quad \text{Eq. 1}$$

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Where:

ER = Emission rate of NO_x in g/HP-hr.

C_d = Measured NO_x concentration in parts per million by volume (ppmv).

1.912 × 10⁻³ = Conversion constant for ppm NO_x to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, horsepower-hour (HP-hr).

(e) To determine compliance with the CO mass per unit output emission limitation, convert the concentration of CO in the engine exhaust using Equation 2 of this section:

$$ER = \frac{C_d \times 1.164 \times 10^{-3} \times Q \times T}{HP-hr} \quad \text{Eq. 2}$$

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Where:

ER = Emission rate of CO in g/HP-hr.

C_d = Measured CO concentration in ppmv.

1.164 × 10⁻³ = Conversion constant for ppm CO to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

(f) For purposes of this subpart, when calculating emissions of VOC, emissions of formaldehyde should not be included. To determine compliance with the VOC mass per unit output emission limitation, convert the concentration of VOC in the engine exhaust using Equation 3 of this section:

$$ER = \frac{C_d \times 1.875 \times 10^{-3} \times Q \times T}{HP-hr} \quad \text{Eq. 3}$$

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Where:

ER = Emission rate of VOC in g/HP-hr.

C_d = VOC concentration measured as propane in ppmv.

1.833×10^{-3} = Conversion constant for ppm VOC measured as propane, to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

(g) If the owner/operator chooses to measure VOC emissions using either Method 18 of 40 CFR part 60, appendix A, or Method 320 of 40 CFR part 63, appendix A, then it has the option of correcting the measured VOC emissions to account for the potential differences in measured values between these methods and Method 25A. The results from Method 18 and Method 320 can be corrected for response factor differences using Equations 4 and 5 of this section. The corrected VOC concentration can then be placed on a propane basis using Equation 6 of this section.

$$RF_i = \frac{C_{i,25A}}{C_{i,method}}$$

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Where:

RF_i = Response factor of compound i when measured with EPA Method 25A.

C_{Mi} = Measured concentration of compound i in ppmv as carbon.

C_{Ai} = True concentration of compound i in ppmv as carbon.

$$C_{Ai} = RF_i \times C_{Mi}$$

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Where:

C_{icorr} = Concentration of compound i corrected to the value that would have been measured by EPA Method 25A, ppmv as carbon.

C_{imeas} = Concentration of compound i measured by EPA Method 320, ppmv as carbon.

$$C_{icorr} = 0.6098 \times C_{imeas} \quad (\text{Eq. 6})$$

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Where:

C_{peg} = Concentration of compound i in mg of propane equivalent per DSCM.

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NOTIFICATION, REPORTS, AND RECORDS FOR OWNERS AND OPERATORS

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§60.4245 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?

Owners or operators of stationary SI ICE must meet the following notification, reporting and recordkeeping requirements.

(a) Owners and operators of all stationary SI ICE must keep records of the information in paragraphs (a)(1) through (4) of this section.

(1) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(2) Maintenance conducted on the engine.

(3) If the stationary SI internal combustion engine is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards and information as required in 40 CFR parts 90, 1048, 1054, and 1060, as applicable.

(4) If the stationary SI internal combustion engine is not a certified engine or is a certified engine operating in a non-certified manner and subject to §60.4243(a)(2), documentation that the engine meets the emission standards.

(b) For all stationary SI emergency ICE greater than or equal to 500 HP manufactured on or after July 1, 2010, that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. For all stationary SI emergency ICE greater than or equal to 130 HP and less than 500 HP manufactured on or after July 1, 2011 that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. For all stationary SI emergency ICE greater than 25 HP and less than 130 HP manufactured on or after July 1, 2008, that do not meet the standards applicable to non-emergency engines, the owner or operator of must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation.

(c) Owners and operators of stationary SI ICE greater than or equal to 500 HP that have not been certified by an engine manufacturer to meet the emission standards in §60.4231 must submit

an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (c)(1) through (5) of this section.

(1) Name and address of the owner or operator;

(2) The address of the affected source;

(3) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(4) Emission control equipment; and

(5) Fuel used.

(d) Owners and operators of stationary SI ICE that are subject to performance testing must submit a copy of each performance test as conducted in §60.4244 within 60 days after the test has been completed. Performance test reports using EPA Method 18, EPA Method 320, or ASTM D6348-03 (incorporated by reference—see 40 CFR 60.17) to measure VOC require reporting of all QA/QC data. For Method 18, report results from sections 8.4 and 11.1.1.4; for Method 320, report results from sections 8.6.2, 9.0, and 13.0; and for ASTM D6348-03 report results of all QA/QC procedures in Annexes 1-7.

(e) If you own or operate an emergency stationary SI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §60.4243(d)(2)(ii) and (iii) or that operates for the purposes specified in §60.4243(d)(3)(i), you must submit an annual report according to the requirements in paragraphs (e)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in §60.4243(d)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §60.4243(d)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in §60.4243(d)(2)(ii) and (iii).

(vii) Hours spent for operation for the purposes specified in §60.4243(d)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in §60.4243(d)(3)(i). The

report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in §60.4.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59177, Oct. 8, 2008; 78 FR 6697, Jan. 30, 2013; 81 FR 59809, Aug. 30, 2016]

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GENERAL PROVISIONS

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§60.4246 What parts of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

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MOBILE SOURCE PROVISIONS

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§60.4247 What parts of the mobile source provisions apply to me if I am a manufacturer of stationary SI internal combustion engines or a manufacturer of equipment containing such engines?

(a) Manufacturers certifying to emission standards in 40 CFR part 90, including manufacturers certifying emergency engines below 130 HP, must meet the provisions of 40 CFR part 90. Manufacturers certifying to emission standards in 40 CFR part 1054 must meet the provisions of 40 CFR part 1054. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060 to the extent they apply to equipment manufacturers.

(b) Manufacturers required to certify to emission standards in 40 CFR part 1048 must meet the provisions of 40 CFR part 1048. Manufacturers certifying to emission standards in 40 CFR part 1048

pursuant to the voluntary certification program must meet the requirements in Table 4 to this subpart as well as the standards in 40 CFR 1048.101.

(c) For manufacturers of stationary SI internal combustion engines participating in the voluntary certification program and certifying engines to Table 1 to this subpart, Table 4 to this subpart shows which parts of the mobile source provisions in 40 CFR parts 1048, 1065, and 1068 apply to you. Compliance with the deterioration factor provisions under 40 CFR 1048.205(n) and 1048.240 will be required for engines built new on and after January 1, 2010. Prior to January 1, 2010, manufacturers of stationary internal combustion engines participating in the voluntary certification program have the option to develop their own deterioration factors based on an engineering analysis.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59177, Oct. 8, 2008]

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DEFINITIONS

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§60.4248 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the CAA and in subpart A of this part.

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) are given in 40 CFR 90.105, 40 CFR 1054.107, and 40 CFR 1060.101, as appropriate. The values for certified emissions life for stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) certified to 40 CFR part 1048 are given in 40 CFR 1048.101(g). The certified emissions life for stationary SI ICE with a maximum engine power greater than 75 KW (100 HP) certified under the voluntary manufacturer certification program of this subpart is 5,000 hours or 7 years, whichever comes first. You may request in your application for certification that we approve a shorter certified emissions life for an engine family. We may approve a shorter certified emissions life, in hours of engine operation but not in years, if we determine that these engines will rarely operate longer than the shorter certified emissions life. If engines identical to those in the engine family have already been produced and are in use, your demonstration must include documentation from such in-use engines. In other cases, your demonstration must include an engineering analysis of information equivalent to such in-use data, such as data from research engines or similar engine models that are already in production. Your demonstration must also include any overhaul interval that you recommend, any mechanical warranty that you offer for the engine or its components, and any relevant customer design specifications. Your demonstration may include any other relevant information. The certified emissions life value may not be shorter than any of the following:

- (i) 1,000 hours of operation.

(ii) Your recommended overhaul interval.

(iii) Your mechanical warranty for the engine.

Certified stationary internal combustion engine means an engine that belongs to an engine family that has a certificate of conformity that complies with the emission standards and requirements in this part, or of 40 CFR part 90, 40 CFR part 1048, or 40 CFR part 1054, as appropriate.

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and carbon dioxide (CO₂).

Emergency stationary internal combustion engine means any stationary reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in §60.4243(d) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in §60.4243(d), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in §60.4243(d).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in §60.4243(d)(2)(ii) or (iii) and §60.4243(d)(3)(i).

Engine manufacturer means the manufacturer of the engine. See the definition of "manufacturer" in this section.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

Installed means the engine is placed and secured at the location where it is intended to be operated.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO₂.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining or natural gas production.

Manufacturer has the meaning given in section 216(1) of the Clean Air Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1048.801.

Model year means the calendar year in which an engine is manufactured (see "date of manufacture"), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see "date of manufacture"), if the annual new model production period is different than the calendar year and includes January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year.

(2) For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was manufactured (see "date of manufacture").

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Pipeline-quality natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions, and which is provided by a supplier through a pipeline. Pipeline-quality natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1,100 British thermal units per standard cubic foot.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to June 12, 2006, with passive emission control technology for NO_x (such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to either: a gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle, aircraft, or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Stationary internal combustion engine test cell/stand means an engine test cell/stand, as defined in 40 CFR part 63, subpart P, that tests stationary ICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Subpart means 40 CFR part 60, subpart J.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake and compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

Volatile organic compounds means volatile organic compounds as defined in 40 CFR 51.100(s).

Voluntary certification program means an optional engine certification program that manufacturers of stationary SI internal combustion engines with a maximum engine power greater than 19 KW (25 HP) that do not use gasoline and are not rich burn engines that use LPG can choose to participate in to certify their engines to the emission standards in §60.4231(d) or (e), as applicable.

[73 FR 3591, Jan. 18, 2008, as amended at 73 FR 59177, Oct. 8, 2008; 76 FR 37974, June 28, 2011; 78 FR 6698, Jan. 30, 2013]

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Table 1 to Subpart J of Part 60—NO_x, CO, and VOC Emission Standards for Stationary Non-Emergency SI Engines ≥100 HP (Except Gasoline and Rich Burn LPG), Stationary SI Landfill/Digester Gas Engines, and Stationary Emergency Engines >25 HP

Engine type and fuel	Maximum engine power	Manufacture date	Emission standards ^a					
			g/HP-hr			ppmvd at 15% O ₂		
			NO _x	CO	VOC ^d	NO _x	CO	VOC ^d
Non-Emergency SI Natural Gas ^b and Non-Emergency SI Lean Burn LPG ^b	100≤HP<500	7/1/2008	2.0	4.0	1.0	160	540	86
		1/1/2011	1.0	2.0	0.7	82	270	60

Non-Emergency SI Lean Burn Natural Gas and LPG	500≤HP<1,350	1/1/2008	2.0	4.0	1.0	160	540	86
		7/1/2010	1.0	2.0	0.7	82	270	60
Non-Emergency SI Natural Gas [BP1] and Non-Emergency SI Lean Burn LPG (except lean burn 500≤HP<1,350)	HP≥500	7/1/2007	2.0	4.0	1.0	160	540	86
	HP≥500	7/1/2010	1.0	2.0	0.7	82	270	60
Landfill/Digester Gas (except lean burn 500≤HP<1,350)	HP<500	7/1/2008	3.0	5.0	1.0	220	610	80
		1/1/2011	2.0	5.0	1.0	150	610	80
	HP≥500	7/1/2007	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Landfill/Digester Gas Lean Burn	500≤HP<1,350	1/1/2008	3.0	5.0	1.0	220	610	80
		7/1/2010	2.0	5.0	1.0	150	610	80
Emergency	25<HP<130	1/1/2009	10	387	N/A	N/A	N/A	N/A
	HP≥130		2.0	4.0	1.0	160	540	86

^aOwners and operators of stationary non-certified SI engines may choose to comply with the emission standards in units of either g/HP-hr or ppmvd at 15 percent O₂.

^bOwners and operators of new or reconstructed non-emergency lean burn SI stationary engines with a site rating of greater than or equal to 250 brake HP located at a major source that are meeting the requirements of 40 CFR part 63, subpart ZZZZ, Table 2a do not have to comply with the CO emission standards of Table 1 of this subpart.

^cThe emission standards applicable to emergency engines between 25 HP and 130 HP are in terms of NO_x + HC.

^dFor purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

[76 FR 37975, June 28, 2011]

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Table 2 to Subpart JJJJ of Part 60—Requirements for Performance Tests

As stated in §60.4244, you must comply with the following requirements for performance tests within 10 percent of 100 percent peak (or the highest achievable) load].

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary SI internal combustion engine demonstrating compliance according to §60.4244	a. Limit the concentration of NO _x in the stationary SI internal combustion engine exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary internal combustion engine;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1, if measuring flow rate	(a) Alternatively, for NO _x , O ₂ , and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter <i>and</i> the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, Appendix A, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, Appendix A.
		ii. Determine the O ₂ concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B ^b of 40 CFR part 60, appendix A-2 or ASTM Method D6522-00 (Reapproved 2005) ^{ad}	(b) Measurements to determine O ₂ concentration must be made at the same time as the measurements for NO _x concentration.

		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 2C of 40 CFR part 60, appendix A-1 or Method 19 of 40 CFR part 60, appendix A-7	(c) Measurements to determine the exhaust flowrate must be made (1) at the same time as the measurement for NO _x concentration or, alternatively (2) according to the option in Section 11.1.2 of Method 1A of 40 CFR part 60, Appendix A-1, if applicable.
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, ^e or ASTM Method D6348-03 ^{de}	(d) Measurements to determine moisture must be made at the same time as the measurement for NO _x concentration.
		v. Measure NO _x at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device	(5) Method 7E of 40 CFR part 60, appendix A-4, ASTM Method D6522-00 (Reapproved 2005), ^{ad} Method 320 of 40 CFR part 63, appendix A, ^e or ASTM Method D6348-03 ^{de}	(e) Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of CO in the stationary SI internal combustion engine exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary internal combustion engine;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1, if measuring flow rate	(a) Alternatively, for CO, O ₂ , and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line (3-

				point long line'). If the duct is >12 inches in diameter <i>and</i> the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, Appendix A, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, Appendix A.
		ii. Determine the O ₂ concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B ^b of 40 CFR part 60, appendix A-2 or ASTM Method D6522-00 (Reapproved 2005) ^{ad}	(b) Measurements to determine O ₂ concentration must be made at the same time as the measurements for CO concentration.
		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 2C of 40 CFR 60, appendix A-1 or Method 19 of 40 CFR part 60, appendix A-7	(c) Measurements to determine the exhaust flowrate must be made (1) at the same time as the measurement for CO concentration or, alternatively (2) according to the option in Section 11.1.2 of Method 1A of 40 CFR part 60, Appendix A-1, if applicable.
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the	(4) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, ^c or	(d) Measurements to determine moisture must be made at the same time as the measurement for CO concentration.

		sampling port location; and	ASTM Method D6348-03 ^{de}	
		v. Measure CO at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device	(5) Method 10 of 40 CFR part 60, appendix A4, ASTM Method D6522-00 (Reapproved 2005), ^{ade} Method 320 of 40 CFR part 63, appendix A, ^e or ASTM Method D6348-03 ^{de}	(e) Results of this test consist of the average of the three 1-hour or longer runs.
	c. Limit the concentration of VOC in the stationary SI internal combustion engine exhaust	i. Select the sampling port location and the number/location of traverse points at the exhaust of the stationary internal combustion engine;	(1) Method 1 or 1A of 40 CFR part 60, appendix A-1, if measuring flow rate	(a) Alternatively, for VOC, O ₂ , and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter <i>and</i> the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, Appendix A, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, Appendix A.

		ii. Determine the O ₂ concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B ^b of 40 CFR part 60, appendix A-2 or ASTM Method D6522-00 (Reapproved 2005) ^{ad}	(b) Measurements to determine O ₂ concentration must be made at the same time as the measurements for VOC concentration.
		iii. If necessary, determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 2C of 40 CFR 60, appendix A-1 or Method 19 of 40 CFR part 60, appendix A-7	(c) Measurements to determine the exhaust flowrate must be made (1) at the same time as the measurement for VOC concentration or, alternatively (2) according to the option in Section 11.1.2 of Method 1A of 40 CFR part 60, Appendix A-1, if applicable.
		iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A-3, Method 320 of 40 CFR part 63, appendix A, ^e or ASTM Method D6348-03 ^{de}	(d) Measurements to determine moisture must be made at the same time as the measurement for VOC concentration.
		v. Measure VOC at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device	(5) Methods 25A and 18 of 40 CFR part 60, appendices A-6 and A-7, Method 25A with the use of a hydrocarbon cutter as described in 40 CFR 1065.265, Method 18 of 40 CFR part 60, appendix A-6, ^{ee} Method 320 of 40 CFR part 63, appendix A, ^e or	(e) Results of this test consist of the average of the three 1-hour or longer runs.

			ASTM Method D6348-03 ^{de}	
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^aAlso, you may petition the Administrator for approval to use alternative methods for portable analyzer.

^bYou may use ASME PTC 19.10-1981, Flue and Exhaust Gas Analyses, for measuring the O₂ content of the exhaust gas as an alternative to EPA Method 3B. AMSE PTC 19.10-1981 incorporated by reference, see 40 CFR 60.17

^cYou may use EPA Method 18 of 40 CFR part 60, appendix A-6, provided that you conduct an adequate pre-survey test prior to the emissions test, such as the one described in OTM 11 on EPA's website (<http://www.epa.gov/ttn/emc/prelim/otm11.pdf>).

^dIncorporated by reference; see 40 CFR 60.17.

^eYou must meet the requirements in §60.4245(d).

[85 FR 63408, Oct. 7, 2020]

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Table 3 to Subpart JJJJ of Part 60—Applicability of General Provisions to Subpart JJJJ

[As stated in §60.4246, you must comply with the following applicable General Provisions]

General provisions citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4248.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4245.

§60.8	Performance tests	Yes	Except that §60.8 only applies to owners and operators who are subject to performance testing in subpart JJJJ.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	Yes	Requirements are specified in subpart JJJJ.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	No	
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

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Table 4 to Subpart JJJJ of Part 60—Applicability of Mobile Source Provisions for Manufacturers Participating in the Voluntary Certification Program and Certifying Stationary SI ICE to Emission Standards in Table 1 of Subpart JJJJ

[As stated in §60.4247, you must comply with the following applicable mobile source provisions if you are a manufacturer participating in the voluntary certification program and certifying stationary SI ICE to emission standards in Table 1 of subpart JJJJ]

Mobile source provisions citation	Subject of citation	Applies to subpart	Explanation
1048 subpart A	Overview and Applicability	Yes	
1048 subpart B	Emission Standards and Related Requirements	Yes	Except for the specific sections below.
1048.101	Exhaust Emission Standards	No	

1048.105	Evaporative Emission Standards	No	
1048.110	Diagnosing Malfunctions	No	
1048.140	Certifying Blue Sky Series Engines	No	
1048.145	Interim Provisions	No	
1048 subpart C	Certifying Engine Families	Yes	Except for the specific sections below.
1048.205(b)	AECD reporting	Yes	
1048.205(c)	OBD Requirements	No	
1048.205(n)	Deterioration Factors	Yes	Except as indicated in 60.4247(c).
1048.205(p)(1)	Deterioration Factor Discussion	Yes	
1048.205(p)(2)	Liquid Fuels as they require	No	
1048.240(b)(c)(d)	Deterioration Factors	Yes	
1048 subpart D	Testing Production-Line Engines	Yes	
1048 subpart E	Testing In-Use Engines	No	
1048 subpart F	Test Procedures	Yes	
1065.5(a)(4)	Raw sampling (refers reader back to the specific emissions regulation for guidance)	Yes	
1048 subpart G	Compliance Provisions	Yes	
1048 subpart H	Reserved		
1048 subpart I	Definitions and Other Reference Information	Yes	
1048 appendix I and II	Yes		
1065 (all subparts)	Engine Testing Procedures	Yes	Except for the specific section below.
1065.715	Test Fuel Specifications for Natural Gas	No	
1068 (all subparts)	General Compliance Provisions for Nonroad Programs	Yes	Except for the specific sections below.

1068.245	Hardship Provisions for Unusual Circumstances	No	
1068.250	Hardship Provisions for Small-Volume Manufacturers	No	
1068.255	Hardship Provisions for Equipment Manufacturers and Secondary Engine Manufacturers	No	

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